Wabash River Coal Gasification Repowering Project

Annual Technology Report
January – December 1999

Work Performed Under
Cooperative Agreement DE-FC21-92MC29310

June 2000

For:
The U.S. Department of Energy
Office of Fossil Energy
National Energy Technology Laboratory
Morgantown, West Virginia

By:

Roy A. Dowd, CHMM
Environmental Supervisor
Wabash River Coal Gasification Repowering Project
444 West Sandford Avenue
West Terre Haute, IN 47885

FETC F 2050.4#
(02/98) OPI=PSI0
Previous Editions Obsolete

U.S. DEPARTMENT OF ENERGY
Federal Energy Technology Center

REQUEST FOR PATENT CLEARANCE FOR RELEASE OF CONTRACTED RESEARCH DOCUMENTS

TO: ✓ For Technical Reports
AAD Document Control
U.S. Department of Energy - FETC
MS 921-143
P.O. Box 10940
Pittsburgh, PA 15236-0940

◆Contract Agreement No.
DE-FC21-92MC29310

Name & Phone No. of DOE COR

☐ For Technical Papers/Journal Articles/Presentations
Mark P. Dvorscak
U.S. Department of Energy
9800 S. Cass Avenue
Argonne, IL 60439
FAX: (630) 252-2779

A. CONTRACTOR ACTION (CONTRACTOR COMPLETES PART A. 1-5)

1. Document Title: Annual Technology Report, January - December 1999

2. Type of Document: ✓ Technical Progress Report ☐ Topical Report ☐ Final Technical Report
☐ Abstract ☐ Technical Paper ☐ Journal Article
☐ Conference Presentation
☐ Other (please specify): ______

3. Date clearance needed: ______

◆ 4. Patent Information.

Yes	No	
☐	✓	Is any patentable subject matter disclosed in the report?
☐	☐	If so, has an invention disclosure been submitted to DOE Patent Counsel? If Yes, identify disclosure number or DOE Case Number ______
☐	✓	Are there any patent-related objections to the release of this report? If so, state the objection.

______

______

◆ 5. Signed Phil Amick Date June 5, 2000
(Contractor)

Name & Phone No. Phil Amick, Global Energy (713) 374-7252

Address 1000 Louisiana, Suite 1550, Houston, TX 77002

B. DOE PATENT COUNSEL ACTION

☐ Patent clearance for release of the above identified document is granted.
☐ Other ______

Signed ______ Date ______
(Patent Attorney)

◆ Must be completed by the contractor

TABLE OF CONTENTS

TABLE OF CONTENTS

EXECUTIVE SUMMARY

The Wabash River Coal Gasification Repowering Project (WRCGRP, or Wabash Project) is a joint venture of Dynegy, Inc. of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana, who have jointly repowered an existing 1950's vintage coal fired steam generating plant with coal gasification combined cycle technology. The Project is located in West Terre Haute, Indiana at PSI's existing Wabash River Generating Station. The Project processes locally mined Indiana high sulfur coal to produce 262 net megawatts of electricity.

PSI and Dynegy are participating in the Department of Energy's Clean Coal Technology Demonstration Program (CCT) to demonstrate coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments. As a CCT Round IV selection, the project will demonstrate integration of an existing PSI steam turbine generator and auxiliaries, a new combustion turbine generator, heat recovery steam generator, and a coal gasification facility to achieve improved efficiency, reduced emissions, and reduced installation costs.

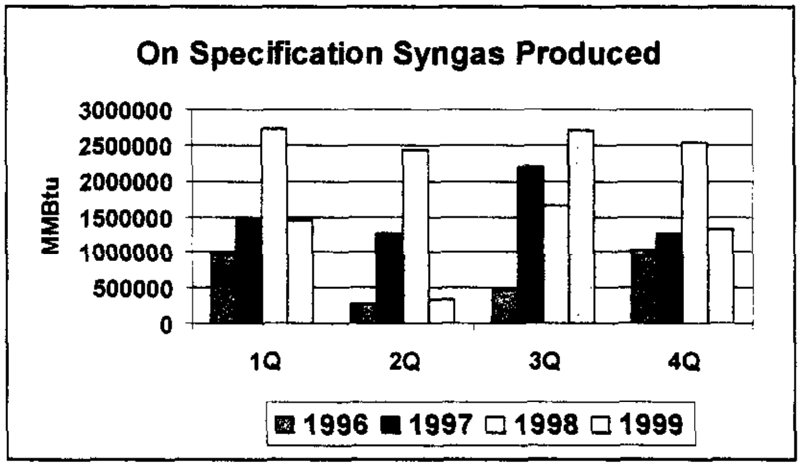
Reaching completion in 1995, the Project represents the largest single train coal gasification combined cycle power plant in the United States. Its design allows for lower emissions than other high sulfur coal fired power plants and a resultant heat rate improvement of approximately 20% over the existing plant configuration.

In late 1998, PSI Energy reached agreement to purchase the Gasification Services contract with Dynegy subject to regulatory approval. Regulatory approval was granted in September of 1999 thus allowing the agreement to move towards an October close. This agreement allows PSI to purchase the remaining term of the 25-year contract, which had become "out-of-market" in comparison to today's natural gas fuel market. Dynegy, in conjunction with PSI and the Department of Energy, are exploring alternatives for continued operation of Wabash River in a more "market-based" mode with a new technology owner. Gasification is not strategic to Dynegy's core business and the search for an appropriate technology owner is nearing completion.

This recent development, coupled with efforts to improve the commercial viability of the Wabash River project, has sharpened the focus to make the technology competitive in today's market. Building on the lessons-learned and the many successes to date, every effort will be expended to incorporate the necessary technologies to pursue value-added uses for syngas produced from coal or other feeds such as is envisioned through forward-thinking concepts like the Department of Energy's "Vision 21" initiative. In the face of the current power market, challenges brought about by abundant and low cost natural gas, Wabash River personnel will aggressively use their collective ingenuity to propel this technology forward as an economically viable conversion tool of carbon feedstocks to higher value products.

The following key objectives were set for 1999:

- Continued improvement of the dry char system to include an evaluation of element metallurgy and a re-look at ceramic based filtration;
- Cross-training of operations and maintenance personnel to reduce maintenance expenditures and improve equipment reliability
- Obtain the data base and experience base necessary to advance and meet the commercial markets for the technology.
- Ensure the facility is prepared to for the year 2000 computer rollover by examining all system controls and computer controlled mechanisms throughout the plant.



1999 marked the fourth full year of commercial operation of the facility. The chart at left illustrates the quantity of "on-specification" syngas produced during each quarter of 1999, while at the same time showing the comparison with the prior three years of operation. Run time for the first quarter of 1999 was hampered by start-up difficulties related to cold weather in January and operation on a fuel source with abnormally high ash fusion temperatures which led to a plugged tap hole near the end of the month. Additionally, a dry char filtration failure in February led to char breakthrough and eventually terminated operations. On March 13th operations were severely impacted for both the first and second quarters when the combustion turbine experienced a failure in the compressor section, which resulted in a shutdown of the facility until June of 1999. In the third quarter the facility exceeded all previous quarterly plant production records by completing 1,178 hours on coal while producing a record-setting 2,712,107 MMBtu's of syngas within specification. This production record was due, in no small part, to the installation of a newly designed slurry mixer, which completed over 1,850 hours of coal operation by the end of the quarter without a failure. This burner continued to operate into the fourth quarter before failing in October after approximately 2000 hours of on-coal service. The third quarter also saw the installation of an upgraded heat-stable-salt removal system and, due to an effective cleaning of the boiler tubes during the extended outage in the second quarter, lower boiler outlet operating temperatures. Operations in the fourth quarter were limited to 18 days in October and 17 days in December. Failures in the newly installed erosion resistant dry char inlet piping and repairs of the boiler tubes and tube-sheet were primarily responsible for limiting operation during the quarter.

The Wabash Project achieved several additional milestones in 1999, including:

- Quarterly Cold Gas Efficiencies higher than 70% for each of the four quarters,
- Operation on an alternate petroleum coke feed source,
- A newly designed mixer operates approximately 2,000 on-coal hours.
- Approximately 4,000 man-hours expended during the extended outage to train Wabash personnel, including cross-training of operators in maintenance procedures,
- Third quarter operational statistics set new records for on-coal hours of operation, on-specification syngas produced, and combustion turbine hours of operation on syngas.
- Utilization of a newly designed boiler cleaning system to reduce downtime, improve boiler tube scale removal, and allow for the recovery of a valuable recyclable mineral.
- Successful rollover of all computer-controlled systems in the plant, without exception, took place on January 1, 2000.

In addition to the aforementioned milestones, Dynegy personnel succeeded in working all of 1999 without an OSHA recordable accident. This marked the first full year of operation without accidents or incidents, which could have been classified as "recordable" under current OSHA guidelines.

Major milestones and activities projected for 2000 include evaluation of new project installations, performance monitoring of the Dry Char Recovery System filtration efficiency, continued focus on gasifier operations and extension of mixer life, and continued demonstration of the commercial viability of the project in a market-based environment.

INTRODUCTION

In September 1991 the United States Department of Energy (DOE) selected the Wabash River Coal Gasification Repowering Project (WRCGRP) for funding under Round IV of the DOE's Clean Coal Technology Demonstration Program. This was followed by nine months of negotiations and a congressional review period. The DOE executed a Cooperative Agreement on July 28, 1992. The project's sponsors, PSI Energy, Inc., and Dynegy, will demonstrate, in a fully commercial setting, coal gasification repowering of an existing generating unit affected by the Clean Air Act Amendments (CAAA). The project will also demonstrate important advances in the coal gasification process for high sulfur bituminous coal. After receiving the necessary state, local and federal approvals, this project began construction in the third quarter of 1993 and commercial operations in the third quarter of 1995. This facility has a planned three-year demonstration period and 22 year operating period (25 years total).

The WRCGRP is a joint venture of Dynegy and PSI Energy, who have developed, designed, constructed, own and now operate a coal gasification facility and a combined cycle (CGCC) power plant (respectively). This specific coal gasification technology, originally developed by The Dow Chemical Company and now owned by Dynegy, was used to repower Unit 1 of PSI's Wabash River Generating Station in West Terre Haute, Indiana. The CGCC power plant produces a nominal 262 net megawatts (MWe) of clean, energy efficient capacity for PSI's customers. In the repowered configuration, PSI and its customers can additionally benefit because this project can enhance PSI's compliance plan under the CAAA regulations. The project utilizes locally mined high sulfur coal and represents the largest CGCC power plant in operation in the United States. This plant is also designed to significantly lower emissions from those of other high sulfur coal fired power plants.

BACKGROUND INFORMATION

Project Inception and Objectives

For CCT Round IV, Public Law 101-121 provided $600 million to conduct cost-shared CCT projects to demonstrate technologies that are capable of replacing, retrofitting, or repowering existing facilities. To that end, a Program Opportunity Notice (PON) was issued by the Department of Energy in January 1991, soliciting proposals to demonstrate innovative energy efficient technologies that were capable of being commercialized in the 1990's. These technologies were to be capable of: (1) achieving significant reductions in the emissions of sulfur dioxide and/or nitrogen oxides from existing facilities to minimize environmental impacts such as transboundary and interstate pollution and/or; (2) providing for future energy needs in an environmentally acceptable manner.

In response to the PON, 33 proposals were received by the DOE in May 1991. After evaluation, nine projects were selected for award. These projects involved both advanced engineering and pollution control technologies that can be "retrofitted" to existing facilities and "repowering" technologies that not only reduce air pollution but also increase generating plant capacity and extend the operating life of the facility.

One of the nine projects selected for funding is the project proposed by the WRCGRP Joint Venture. This proposal (a Joint Venture between Destec Energy, Inc. (Dynegy) of Houston, Texas and PSI Energy, Inc. of Plainfield, Indiana) requested financial assistance from DOE for the design, construction, and operation of a nominal 2500 ton-per-day (262 net MWe) two-stage, oxygen-blown, coal gasification combined cycle (CGCC) repowering demonstration project. The project, named the Wabash River Coal Gasification Repowering Project, is located at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The project location and site are shown in Figures 1, 2, 3, and 4 in Appendix B. The demonstration project utilizes advanced coal gasification technology in a commercial repowering setting to repower an existing generating unit affected by the Clean Air Act Amendments of 1990. Sulfur emissions from the repowered generating unit will be reduced by more than 90%, while at the same time increasing electrical generating capacity over 150%. The project, including the demonstration phase, will last 79 months. The DOE's share of the project cost will be $219 million.

The CGCC system consists of: (See Figures 5 & 5A)

- Dynegy's oxygen-blown, entrained flow, two stage coal gasifier, which is capable of utilizing high sulfur bituminous coal;
- An air separation unit;
- A gas conditioning system for removing sulfur compounds and particulate;
- Systems or mechanical devices for improved coal feed and all necessary coal handling equipment;
- A combined cycle power generation system wherein the gasified coal syngas is combusted in a combustion turbine generator;
- A heat recovery steam generator.

The result of repowering is a CGCC power plant with low environmental emissions (SO_2 of less than 0.25 lbs/MMBtu and NO_x of less than 0.1 lb/MMbtu) and high net plant efficiency. The repowering increases unit output, providing a total CGCC capacity of nominal 262 net MWe. The project demonstrates important technological advancements in processing high sulfur bituminous coal.

In addition to the joint venture members, PSI and Dynegy, the Phase II project team included Sargent & Lundy, who provided engineering services to PSI, and Dow Engineering, who provided engineering services to Dynegy.

The potential market for repowering with the demonstrated technology is large and includes many existing utility boilers currently fueled by coal, oil, or natural gas. In addition to greater, more cost effective reduction of SO_2 and NO_x emissions attainable by using the gasification technology, net plant heat rate is improved. This improvement is a direct result of the combined cycle feature of the technology, which integrates a combustion topping cycle with a steam bottoming cycle. This technology is suitable for repowering applications and can be applied to any existing steam cycle located at plants with enough land area to accommodate coal handling and storage and the gasification and power islands.

One of the project objectives is to advance the commercialization of coal gasification technology. The electric utility industry has traditionally been reluctant to accept coal gasification technology and other new technologies as demonstrated in the U.S. and abroad because the industry has no mechanism for differentiating risk/return aspects of new technologies. Utility investments in new technologies may be disallowed from rate-base inclusion if the technologies do not meet performance expectations. Additionally, the rates of return on these are regulated at the same level as established lower risk technologies. Therefore, minimal incentives exist for a utility to invest in, or develop, new technologies. Accordingly, most of the risk in new technologies has traditionally been assumed by the supplier.

The factors described above are constraints to the development of, and demand for, clean coal technologies. Constraints to development of new technologies also exist on the supply side. Developers of new technologies typically self-finance or obtain financing for projects through lenders or other equity investors. Lenders will generally not assume performance and operational risks associated with new technology. The majority of funds available from lending agencies for energy producing projects is for technologies with demonstrated histories in reliability, maintenance costs and environmental performance. Equity investors who invest in new energy technologies also seek higher returns to accept risk and often require the developer of the new technology to take performance and operational risks.

Consequently, the overall scenario results in minimum incentives for a commercial size development of new technologies. Yet without the commercial size test facilities, the majority of the risk issues remain unresolved. Addressing these risk issues through utility scale demonstration projects is one of the primary objectives of DOE's Clean Coal Technology Program.

The WRCGRP was developed in order to demonstrate the Dynegy Coal Gasification Technology in an environment, and at such a scale, as to prove the commercial viability of the technology. Those parties affected by the success of this Project include the coal industry, electric utilities, ratepayers, and regulators. Also, the financial community, which provides the funds for commercialization, is keenly interested in the success of this project. Without a demonstration satisfying all of these interests, the technology will make little advancement. Factors of relevance to further commercialization are:

- The Project scale (262 net MWe) is compatible with all commercially available advanced gas turbines and thus completely resolves the issue of scale-up risks.

- The operational term of the Project is expected to be approximately 25 years including the DOE demonstration period of the first 3 years. This should alleviate any concerns that the demonstration does not define a fully commercial plant from a cost and operational viewpoint.

- The Project dispatches on a utility system and is called upon to operate in a manner similar to other utility generating units.

- The Project operates under a service agreement that defines guarantees of environmental performance, capacity, availability, coal to gas conversion efficiency and maximum auxiliary power consumption. This agreement serves as a model for future commercialization of the Dynegy Coal Gasification Technology and defines the fully commercial nature of the Project.

- The Project is designed to accommodate most coals available in Indiana and typical of those available to Midwestern utilities, thereby enabling utilities to judge fuel flexibility. The Project also enables testing of varying coal types in support of future commercialization of the Dynegy Coal Gasification Technology.

Plant Description

The WRCGRP Joint Venture participants developed and separately designed, constructed, own, and currently operate the syngas and power generation facilities making up the CGCC facility. Coal Gasification technology owned by Dynegy, is used to repower one of six units at PSI's Wabash River Generating Station in West Terre Haute, Indiana. The Project will operate under a 25 year contact. In the repowered configuration, PSI and its customers additionally benefit because of the role the Project plays in PSI's Clean Air Act compliance plan. The CGCC power plant produces 262 net MWe of clean, energy efficient, cost effective capacity for PSI's customers. An additional economic benefit to the State of Indiana is that the project not only represents the largest CGCC power plant in operation, but also features lower emissions than other large, high sulfur coal fired power plants.

The gasification process can be described in the following manner: (see Figures 6 and 7 in Appendix B): Coal is ground with water to form a slurry and then pumped into a gasification vessel where oxygen is added to form a hot, raw gas through partial combustion. Most of the non-carbon material in the coal melts and flows out the bottom of the vessel as slag (a black, glassy, non-leaching, sand-like material). The hot, raw gas is then cooled in a heat exchanger to generate high-pressure steam. Particulates, sulfur, and other impurities are removed from the gas to make acceptable fuel for the gas turbine. By-products of the gasification process (e.g. sulfur and slag) will be sold thus mitigating the waste disposal problems of competing technologies.

The synthetic fuel gas (syngas) is piped to a combustion turbine generator, which produces approximately 192 MWe of electricity. A heat recovery steam generator (HRSG) recovers gas turbine exhaust heat to produce high-pressure steam. This steam, combined with the steam generated in the gasification unit, supplies an existing steam turbine generator in PSI's plant to produce an additional 104 MWe. The net plant heat rate for the entire new and repowered unit is approximately 9,000 Btu/kWh (Higher Heating Value or HHV), representing an improvement of approximately 20% over the existing unit. The project heat rate is among the lowest of commercially operated coal fired facilities in the United States.

The Dynegy Coal Gasification process was originally developed by The Dow Chemical Company during the 1970's in order to diversify its fuel base. The technology being used at Wabash is an extension of the experience gained from pilot plants and the full-scale commercial facility, Louisiana Gasification Technology, Inc. (LGTI), which operated from April 1987 until November 1995.

In order to generate data necessary for commercialization, the Joint Venture has chosen a very ambitious approach for incorporation of novel technology in the project. This approach is supported by PSI's desire to have another proven technology alternative available for future repowering or new base load units. Dynegy desires to enhance its competitive position relative to other clean coal technologies by demonstrating new techniques and process enhancements as well as gaining information about operating cost and performance expectations. The incorporation of novel technology in the project will enable utilities to make informed commercial decisions concerning the utilization of Dynegy's technology, especially in a repowering application.

New enhancements, techniques and other improvements included in the novel technology envelope for the project are as follows:

- **A novel application** of integrated coal gasification combined cycle technology will be demonstrated at the project for the first time – **repowering of an existing coal fired power generating unit.**

- The **coal fuel** for the project **is high sulfur bituminous coal**, thus demonstrating the environmental performance and energy efficiency of Dynegy's advanced two-stage coal gasification process. Previous Dynegy technology development has focused on lower rank, more reactive coals.

- **Hot/Dry particulate removal/recycle will be demonstrated at full commercial scale** by the project. Dow's original operational plant utilized a wet scrubber system to remove particulates from the raw syngas.

Other coal gasification process enhancements included in the project to improve the efficiency and environmental characteristics of the system are as follows:

- **Syngas Recycle** provides fuel and process flexibility while maintaining high efficiency.

- **A High Pressure Boiler** cools the hot, raw gas by producing steam at a pressure of 1,600 pounds per square inch absolute (psia).

- **The Carbonyl Sulfide (COS) Hydrolysis** system incorporated at the project is Dynegy's first application of this technology. This system is necessary to attain the high level of sulfur removal at the project.

- **The Slag Fines Recycle** system recovers most of the carbon present in the slag by-products stream and recycles it back for enhanced carbon conversion. This also results in a high quality slag by-product.

- **Fuel Gas Moisturization** is accomplished at the project by the use of low level heat in a concept different from that used by Dynegy before. This concept reduces the steam injection required for nitrous oxide (NO_x) control in the combustion turbine.

- Sour water, produced by condensation as the syngas is cooled, is processed differently from the method used at LGTI. This novel **Sour Water System**, used at the project, allows more complete recycling of this stream, reducing waste water and increasing efficiency.

- An oxygen plant producing **95 percent pure oxygen** is used by the project. This increases the overall efficiency of the project while lowering the power required for production of ultra-pure oxygen.

- The **power generation facilities** included in the project incorporates the latest advancements in combined cycle system design while accommodating design constraints necessary to repower the existing Unit 1 steam turbine.

- The project incorporates an **Advanced Gas Turbine** with a new design compressor and higher pressure ratios.

- **Integration between the Heat Recovery Steam Generator (HRSG) and the Gasification Facility** has been optimized at the project to yield higher efficiency and lower operating costs.

- **Repowering of the Existing Steam Turbine** involved upgrading the unit in order to accept increased steam flows generated by the HRSG. In this manner, the cycle efficiency is maximized because more of the available energy in the cycle will be utilized.

The gasification/repowering approach offers the following advantages as compared to other options:

- This is a viable alternative that will add life to existing older units. The primary assumption, however, is that reasonable life exists in the steam turbine to be repowered. If reasonable life exists in the steam turbine, the approach eliminates the need for refurbishment of much of the high wear components of conventional pulverized coal units. Three such items are the boiler, coal pulverizers and high energy piping systems.

- This approach is an alternative for Clean Air Act compliance compared with the traditional scrubber approach. Although space constraints are similar for the installed facility, waste storage requirements are smaller due to salable by-products in lieu of onsite storage of scrubber sludge.

- This approach provides a use for high sulfur coal. This is particularly important in areas such as Indiana, and much of the eastern United States, where high sulfur coal is abundant and provides a substantial employment base.

Project Management

The WRCGRP Joint Venture (JV) established a Project Office for the execution of the project. The Project Office is located at Dynegy's corporate offices in Houston, Texas. All management, reporting, and project reviews for the project are carried out as required by the Cooperative Agreement. The JV partners, through a JV Agreement, are responsible for the performance of all engineering, design, construction, operation, financial, legal, public affairs, and other administrative and management functions required to execute the project. A JV Manager has been designated as responsible for the management of the project. A JV organization chart is shown as Figure 8. The JV Manager is the official point of interface between the JV and the DOE for the execution of the Cost Sharing Cooperative Agreement. The JV Manager is responsible for assuring that the Project is conducted in accordance with the cost, schedule, and technical baseline established in the Project Management Plan (PMP) and subsequent updates.

Major Activities and Milestones

The Project Cooperative Agreement (CA) was signed on July 28, 1992, with an effective date of August 1, 1992. Under the terms of the CA, Project activities are divided into three phases:

- Phase I Engineering and Procurement
- Phase II Construction and Startup
- Phase III Demonstration

In addition, for purposes of the CA, the Project is divided into three sequential Budget Periods. The expected duration of each budget period is as follows:

- Budget Period 1 10 months
- Budget Period 2 27 months
- Budget Period 3 39 months

The Project Milestone Schedule is provided in Figure 9.

Phase I Activities – Engineering and Procurement

Under the provisions of the CA, the work activity in Phase I (engineering and procurement) focused on detailed engineering of both the syngas and power plant elements of the project which included design drawings, construction specifications and bid packages, solicitation documents for major hardware and the procurement. Site work was undertaken during this time period to meet the overall construction schedule requirements. The Project Team includes all necessary management, administrative and technical support.

The activities completed during this period were those necessary to provide the design basis for construction of the plant, including capital cost estimates sufficient for financing, and all necessary permits for construction and subsequent operation of the facility.

The work during Phase I can be broken down into the following main areas:

- Project Definition Activities
- Plant Design
- Permitting and Environmental Activities

Each of these activities is briefly described below. All Phase I activities were complete by 1993.

Project Definition Activities

This work included the conceptual engineering to establish the project size, installation configuration, operating rates and parameters. Definition of required support services, all necessary permits, fuel supply, and waste disposal arrangements were also developed as part of the Project Definitions Activities. From this information, the cost parameters and project economics were established (including capital costs, project development costs and operation and maintenance costs). Additionally, all project agreements necessary for construction of the plant were concluded. These include the CA and the gasification services agreement.

Plant Design

This activity included preparation of design and major equipment specifications along with plant piping and instrumentation diagrams (P&ID's), process control releases, process descriptions, and performance criteria. These were prepared in order to obtain firm equipment specifications for major plant components, which established the basis for detailed engineering and design.

Permitting and Environmental Activities

During Phase I, applications were made and received for the permits and environmental activities necessary for the construction and subsequent operation of the project. The major project permits included:

- Indiana Utility Regulatory Commission – The state authority reviewed the project (under a petition from PSI for a Certificate of Necessity) to ensure the project will be beneficial to the state and PSI ratepayers. The technical and commercial terms of the project were reviewed in this process.

- Air Permit – This permit details the allowable emission levels for air pollutants from the project. It was issued under standards established by the Indiana Department of Environmental Management (IDEM) and the United States Environmental Protection Agency (USEPA) Region V. This permit also included within it the authority to commence construction.

- NPDES Permit – This National Pollutant Discharge Elimination System permit details and controls the quality of waste water discharge from the project. It was reviewed and issued by the Indiana Department of Environmental Management. For this project it will be a modification of the existing permit for PSI's Wabash River Generating Station.

- NEPA Review – The National Environmental Policy Act review was carried out by the DOE based on project information provided by the participants. The scope of this review was comprehensive in addressing all environmental issues associated with potential project impacts on air, water, terrestrial, quality, health and safety, and socioeconomic impacts.

Miscellaneous permits and approvals necessary for construction and subsequent operation of the project included the following.

- FAA Stack Height/Location Approval
  Controlling Authority: Federal Aviation Administration

- Industrial Waste Generator
  Controlling Authority: Indiana Department of Environmental Management

- Solid Waste

- FCC Radio License

- Spill Prevention Plan

- Wastewater Pollution Control Device Permit
  Controlling Authority: IDEM

Phase II Activities – Construction

Construction activities occurred in Phase II and included the necessary construction planning and integration with the engineering and procurement effort. Planning the construction of the project began early in Phase I. Separate on-site construction staffs for both Dynegy and PSI were provided to focus on their respective work for each element of the Project. Construction personnel coordinated the site geotechnical surveys, equipment delivery, storage and lay down space requirements. The construction activities included scheduling, equipment delivery, erection, contractors, security and control.

The detail design phase of the project includes engineering, drawings, equipment lists, plant layouts, detail equipment specifications, construction specification, bid packages and all activities necessary for construction, installation, and startup of the project.

Performance and progress during this period was monitored in accordance with previously established baseline plans. There were no Phase II activities conducted during this reporting period.

Phase III Activities – Demonstration Period

Phase III consists of a three-year demonstration period. The operation effort for the project began with the development of the operating plan including integration with the early engineering and design work of the project. Plant operation input to engineering was vital to assure optimum considerations for plant operations and maintenance and to assure high reliability of the facilities. The operating effort continued with the selection and training of operating staff, development of the operating manuals, coordination of startup with construction, planning and execution of plant commissioning, conduct and documentation of the plant acceptance test, and continued operation and maintenance of the facility throughout the demonstration period.

Phase III activities are intended to establish the operational aspects of the project in order to prove the design, operability and longevity of the plant in a fully commercial utility environment.

Budget Periods

For ease of administration, the Project is divided into three budget periods with expected durations of:

- Budget Period 1 10 months
- Budget Period 2 27 months
- Budget Period 3 39 months

Budget Period 1 activities include pre-DOE award and project definition tasks, preliminary engineering work, and permitting activities. Budget Period 2 activities include detailed engineering, procurement, construction, pre-operations training tasks, and startup. Budget Period 3 activities include the three-year demonstration period. The budget period costs were originally projected and revised as follows:

	Original	Revised
Budget Period 1 DOE Share	$43,175,801	$21,864,591
Budget Period 2 DOE Share	$102,523,632	$144,934,842
Budget Period 3 DOE Share	$52,300,567	$52,300,567
Total	$198,000,000	$219,100,000

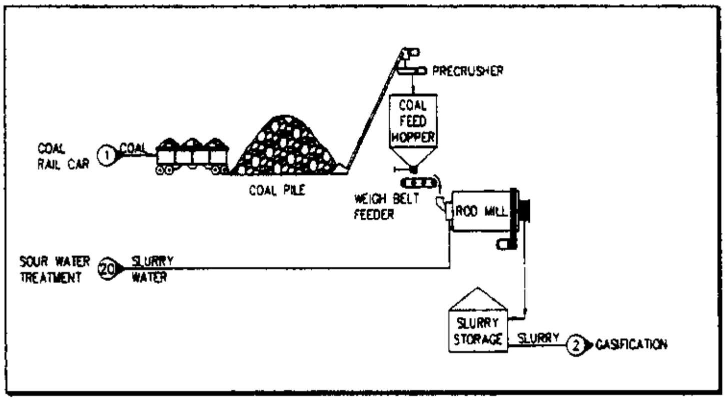
ACTIVITIES DURING 1999

A current Project schedule, indicating milestone dates and current status, is provided as Figure 10.

1999 Phase III Activities – Demonstration Period

The plant processes are broken down by area to better describe the activities during 1999 and focus on the accomplishments and areas identified for improvement. Each area is preceded by an illustrated representation of the process along with a general process description.

COAL PREPARATION AND SLURRY AREA



The diagram at left depicts the process of coal slurry preparation. PSI has the responsibility of delivering coal and transporting it to the feed hopper. Coal enters the feed hopper then is fed to the rod mill via a weigh belt feeder. In 1999 all coals processed originated in Indiana and included both Hawthorne and Miller Creek coal. The coal is mixed with limestone (if required based on ash fusion temperature) at the mine site, which is added as a fluxing agent to enhance slag flow characteristics in the gasifier. Limestone addition is not necessary for lower ash fusion coals. Treated water recycled from other areas of the gasification process is added to the coal at a controlled rate to produce the desired slurry solids concentration of approximately 62%. The use of a wet rod mill reduces potential fugitive particulate emissions from the grinding operations. Collection and reuse of water within the gasification process minimizes water consumption and effluent wastewater volume.

The slurry is stored in an agitated tank, which is large enough to supply the gasifier needs during forced rod mill outages. Most expected maintenance requirements of the rod mill and storage tank can thus be accomplished without interrupting gasifier operation.

All tanks, drums, and other areas of potential atmospheric exposure of the product slurry or recycle water are covered and vented into the tank vent collection system for vapor emission control. The entire slurry preparation facility is paved and curbed to contain spills, leaks, wash down, and rain water. All runoff is carried by a trench system to a sump where it is pumped into the recycle water storage tank to be reused in the coal slurry preparation system.

Primary coal characteristics, which effect operation of the gasifier include the following:

- Ash Content
- Sulfur
- Carbon
- Hydrogen
- Nitrogen
- Oxygen
- Btu Content

Hawthorne and Miller Creek coals were fed at various ratios during 1999. Blends ratios were adjusted as necessary to ensure proper slag flow through the tap hole while maintaining consistent Higher Heating Values (HHV) for the syngas. The following table illustrates the average values for these constituents in 1999 while also outlining the variability that was encountered during the year:

	Hawthorne Coal/Miller Creek Coal Blend		
	Average	**High**	**Low**
Ash, %	11.8	14.92	11.23
Sulfur, %	2.95	3.44	2.67
Carbon, %	69.66	71.3	67.6
Hydrogen, %	4.85	4.97	4.73
Nitrogen, %	1.44	1.44	1.43
Oxygen, %	8.48	12.26	7.02
Btu/lb (Received)	10645	10875	10413
Btu/lb (Dry)	12566	12749	12472

The rod mill is designed to crush the coal to a desired particle size to ensure stable "slurryability" and optimum carbon conversion in the gasifier. Due to problems encountered in 1997 and 1998 with foreign material being processed from the coal pile and through the rod mill, trommel screen damage has been carefully tracked throughout the year. The trommel screen is designed to prevent oversized particles and debris from entering the slurry storage tank. Preventative Maintenance (PM) inspections have been increased on the screen and the incidences of failure have been almost eliminated. During the first quarter of 1999 the trommel screen was replaced during an extended outage. The screen replacement provided the opportunity for some metallurgy improvements and the addition of erosion resistant materials in the mill outlet chute. As a result of this project no further rod mill trommel screen failures have occurred during the 1999 campaign.

The ventilation of the rod mill trommel screen was upgraded as well. The ventilation upgrade increased the efficiency of the vent collection system thus lowering the ammonia concentration in and around the rod mill building. Data from air monitoring collected during the second quarter indicates more than an 80% reduction in ammonia concentration has been realized since this improvement was completed.

In 1999, the coal preparation and feed area accounted for 61 hours of overall plant downtime (approximately 1.9% of total gasification plant downtime). In comparison, approximately 10 hours of total downtime was experienced in 1998 in this area. The following is a brief description of the causation factors and corrective measures that occurred in 1999:

- During a start-up in early February, the slurry feed system logged 23 hours of downtime due to problems with pumps and instrumentation. During two transfers to coal operation, a slurry pressure transmitter failed low resulting in a mixer trip. The associated shutdown alarm was re-written in the second quarter to require low signals from both of the redundant pressure transmitters before initiating a mixer trip.

- Additionally, during the same start up period, a piston failure occurred on one of the positive displacement gasifier feed pumps. This resulted in contamination of the piston flush water with coal slurry, which necessitated shutdown of the remaining positive displacement pumps interrupting coal operation for 5 hours. The root cause of the failure was prolonged use of a hard water supply for the piston flush system. Operating personnel have been instructed to use only soft water for piston flushes.

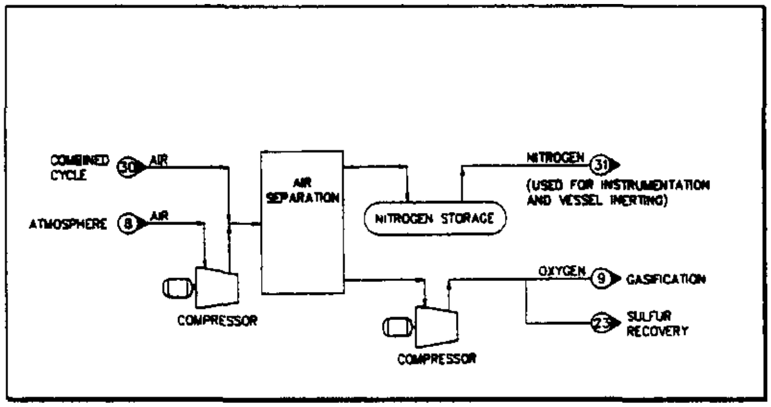
- In June, July, September, and December failures in the slurry feed system resulted in trips off of coal operations resulting in 16 total hours of plant downtime. In each event, the suction of the stuffing pump plugged causing an interruption of slurry delivery to the positive displacement pumps. In the June, July, and December events, the interrupted flow subsequently caused both slurry mixers to trip on high oxygen-to-coal ratio. In September, the problem led to a trip of a single mixer. The root cause of the problem was identified as excessive agitator blade wear in the slurry storage tank. The loss of agitation efficiency resulted in the accumulation of solids near the pump suction in the tank. When the accumulation became significant, the corresponding solids would break loose and plug the suction side of the stuffing pumps. To correct the problem, the blades on the agitator will be lengthened and coated with wear resistant material during the spring outage in 2000.

- Erosion of slurry piping components was responsible for three transfers off of coal in October, which resulting in 22 hours of downtime. Two of the failures were attributed to improper material selection for valves in the slurry piping system. During the November outage, the failed valves, as well as some others, were upgraded to a more erosion resistant metallurgy.

In 1999 a total of over 369,589 tons (as received) of coal were processed through the rod mill. Slurry fed from the slurry feed tank to the gasifier accounted for approximately 7,772,568 MMBtu's. The following table illustrates the quarterly usage of coal feed stock in 1999:

1998	**"As Received" Coal Feed (Tons)**	**MMBtu**
1st Quarter	93,969	1,921,831
2nd Quarter	21,100	441,884
3rd Quarter	172,175	3,658,860
4th Quarter	82,618	1,749,993
Total	**369,589**	**7,772,568**

AIR SEPARATION UNIT (ASU)



The Air Separation Unit (ASU) depicted at left, contains: an air compression system; an air purification and cryogenic distillation system; an oxygen compression system; and, a nitrogen storage and handling system. Atmospheric air is compressed in a centrifugal compressor then cooled in a chiller tower to approximately 40 degrees F. The cooled air is then purified through molecular sieve absorbers where atmospheric contaminants (H_2O, CO_2, hydrocarbons, etc.) are removed to prevent these contaminants from freezing during cryogenic distillation. The dry, carbon dioxide-free air is separated into 95% purity oxygen, high purity nitrogen, and waste gas in the cryogenic distillation system. The gaseous oxygen is compressed in a centrifugal compressor and fed to the gasifier. Liquid nitrogen (LIN) is also produced in the distillation system with a portion being vaporized for use as gaseous nitrogen in the gasification system and the balance being stored for use during ASU plant outages.

In 1999 the ASU contributed 340 hours of gasification plant downtime (approximately 10.5% of total downtime) compared to 397 hours (or approximately 20.4%) in 1998. Several key outages occurred in 1999 which led to the increase in ASU contributions to plant downtime. Those occurrences were:

- In January, the unit suffered 15 hours of startup delay when the nitrogen storage tank ran short of liquid. Emergency road conditions caused by ice and snow prevented the requested nitrogen delivery, which delayed gasifier startup. In response to this shortfall, two new contracts have been negotiated with spot market nitrogen suppliers as a hedge against delivery and production problems.

- A second short production delay of 11 hours occurred on 2-Feb-99, due to the performance of a safety test on the ASU's distillation exchanger. Since May of 1997, two ASU plant explosions occurred worldwide resulting from the operation of distillation exchangers of similar design. The test was recommended by the supplier of the unit and was performed to expose risk factors associated with continued exchanger operation at the Wabash River ASU facility. The test results indicated that the ASU at Wabash was at very low risk.

- The failure of an automatic valve to properly seat prevented depressurization of an absorber bed that interrupted oxygen supply and resulted in 15 hours of gasifier downtime. A temporary fix involving manual operation was implemented until the valve was repaired during the next scheduled outage.

- Failure of the derime header inside the main exchanger cold box resulted in 14 days of downtime in August. The root cause was determined to be insufficient weld penetration at the socket welds in the header during plant construction. The weld repairs required only two days but entry into the cold box required the removal of 10,000 cubic feet of insulation and a subsequent process derime to remove moisture and organics from the system. The repaired header was dye tested to insure full weld penetration and supports were added to further enhance reliability.

Several projects were implemented in the ASU in 1999 to enhance plant performance. Those projects were:

- Motor purges were incorporated for the ASU's large motors (>9000 HP) to facilitate long life without moisture damage.

- ASU operations took advantage of the extended downtime in the second quarter to conduct a 12 day plant "derime" (purge of H_2O moisture and CO_2), the first since initial startup in the 1995. Derime requires the plant to de-inventory all cryogenic liquids and then heat all process vessels and piping using hot, dry air. A sixteen-hour heat soak ensures that all moisture and carbon dioxide are driven out prior to cool-down. The resulting plant is free of ice and hydrocarbons, which enhances the reliability and safety of the operation. Thermowells and RTDs were added to the system to facilitate data collection during plant derime activities. Air Liquide, manufacturer of the ASU, has revised their recommended derime frequency from 5 years to 2 years.

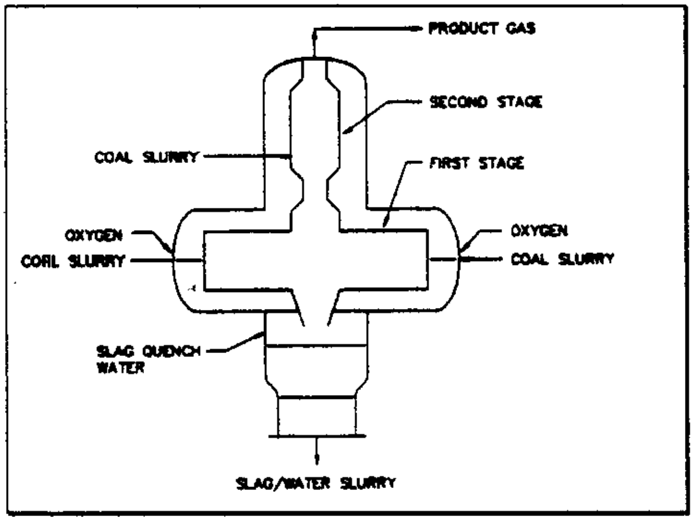
- A major upgrade of the Westinghouse control system was completed and tested to insure Y2K compatibility.

- The adsorber sequencer valve solenoids, which were not rated for outdoor service, were upgraded to prevent the actuator from working itself loose from the valve. This problem was identified in the fourth quarter of 1998 when the actuator came loose from the valve and resulted in a limit switch failure which prevented the regeneration sequence from completing. Additionally, a new bushing design was implemented on the adsorber system valve that caused lost production during the third quarter. This new design, if successful, will provide a permanent fix for several other valves in the same system.

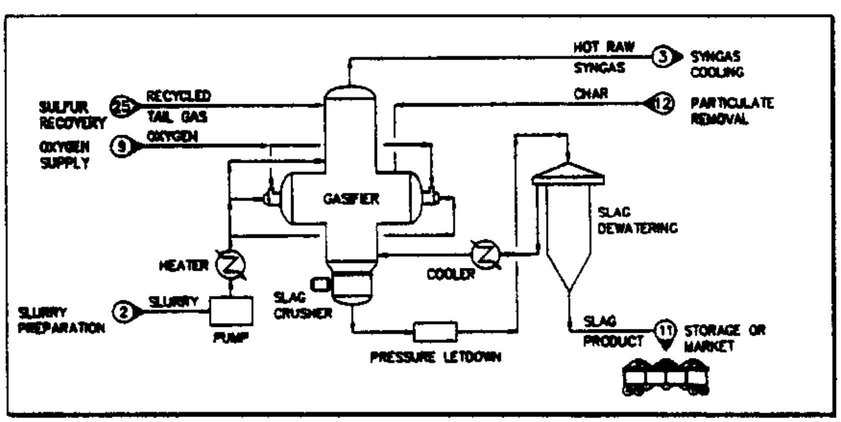
- The inlet guide vane (IGV) system on the main air compressor (MAC) was replaced with new "vane" type actuators and several other modifications were made to the IGV system to insure reliability. These improvements are expected to eliminate the ASU's largest availability issues that have been previously reported in the 1997 and 1998 Annual Technology Reports.

- Modifications to the water distribution trays in the water chiller tower were performed to address nitrogen production limitations experienced during the summer of 1999.

GASIFICATION AND SLAG HANDLING

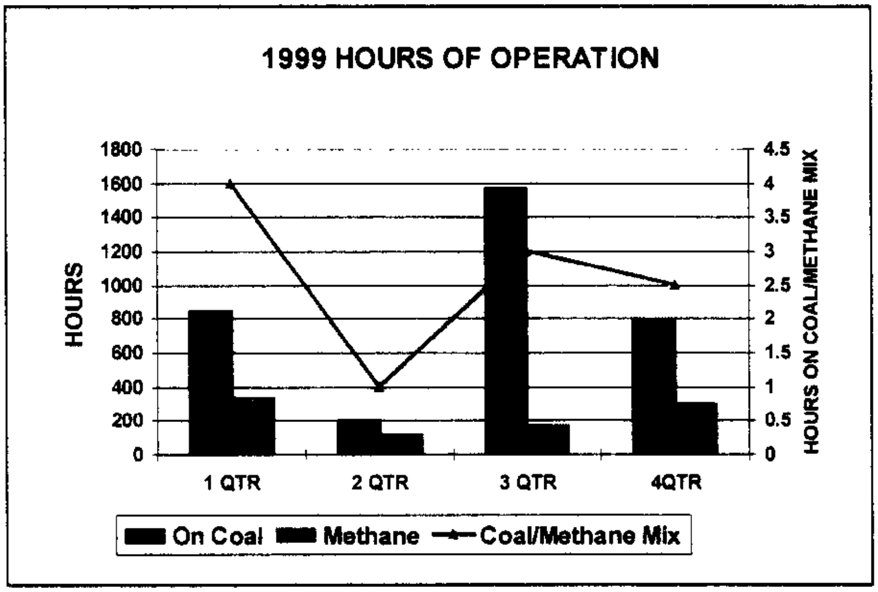


The Dynegy gasifier consists of two stages; a slagging first stage, and an entrained flow, non-slagging second stage. The first stage is a horizontal, refractory-lined vessel in which coal slurry and oxygen are combined in partial combustion quantities at an elevated temperature (nominally 2500 degrees F) and pressure (400 psia). Dry particulate (char) filtered from the raw sygnas downstream of the gasifier is also recycled to the first stage gasification process. The oxygen and coal slurry are fed to the gasifier and atomized through two opposing mixing nozzles once the vessel has been adequately preheated on natural gas (methane) operation. Oxygen feed rate to the mixers is carefully controlled to maintain the gasification temperature above the ash fusion point, thereby ensuring good slag removal. Produced synthetic gas (syngas) consists primarily of hydrogen, carbon dioxide, carbon monoxide and water vapor. Sulfur in the coal is converted primarily to hydrogen sulfide with a portion converted to carbonyl sulfide. Both sulfur species are removed in downstream processes. Mineral matter in the coal forms a molten slag, which is continuously tapped from the gasifier. The second stage is a vertical refractory lined section in which additional coal slurry is reacted with the hot syngas stream exiting the first stage. This additional slurry serves to lower the temperature of the gas exiting the first stage to 1900 degrees F by vaporization of the slurry and endothermic reactions. The coal undergoes de-volatilization and pyrolysis thereby generating more gas at a higher heating value. No additional oxygen is added to the second stage. The partially reacted coal (char) and entrained ash is carried overhead with the gas. Natural gas (methane) is utilized for preheating the gasifier. No product syngas is generated for PSI's consumption during the pre-heat process while in methane operations.



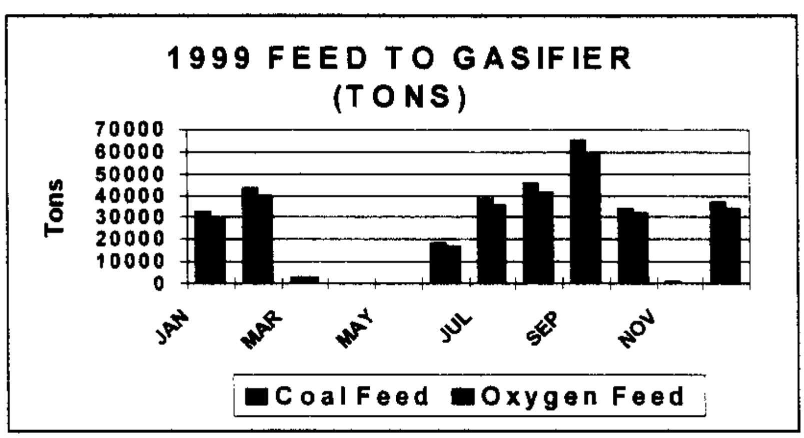
Slag flows continuously through the tap hole of the first stage into a water quench bath, located below the first stage. The slag is then crushed and removed through a continuous pressure let-down system as a slag/water slurry. This process of continuous slag removal is compact, minimizes overall height of the gasifier structure, eliminates the high-maintenance requirements of problem-prone lock hoppers, and completely prevents the escape of raw gasification products to the atmosphere during slag removal.

The slag slurry leaving the pressure let down system flows into a de-watering bin. The bulk of the slag will settle out in this bin, while the water overflows a weir at the top of the bin to a settler in which the slag fines are settled and removed. The clear water gravity-flows out of the settler and is pumped through heat exchangers where it is cooled as the final step before being returned to the gasifier quench section. De-watered slag is loaded into a truck or rail car for transport to market or its storage/disposal site located on the south end of the Wabash River Generating station. The fines slurry from the bottom of the settler is recycled to the slurry preparation area. The de-watering system contains de-watering bins, a water tank, cooler and water circulation pump. All tanks, bins, and drums are vented to the tank vent collection system to limit fugitive emissions.



During GSI's operational campaigns in 1999, the gasifier operated on coal 3,419 hours. Additionally, a short petroleum coke trial during the third quarter ran for 55 hours on petcoke and 22 hours on a petcoke/coal blend. During heat-up operations, the gasifier operated on methane and a blend of coal/methane for 932.5 hours (922 hours on methane, and 10.5 hours on a coal/methane mix). It must be reiterated that syngas generated during heat-up operations is not suitable for use as fuel for the combustion turbine and that coal/methane mix is simply a measure of transition from methane heat-up to coal operation. Methane operations indicated in the graph above indicate methane and coal/methane mix hours for heat-up of the gasifier and associated equipment and the transition to full coal operations.

Coal and petcoke to the gasifier totaled over 315,951 tons feed (moisture free basis) for 1999 and oxygen feed from the ASU to the gasifier totaled in excess of 289,930 tons. This material feed was utilized in the production of over 5,813,151 MMBtu of on-spec syngas. By-product slag produced from the process totaled approximately 45,216 tons.



In 1999 the Gasification and Slag Handling area contributed 806 hours of downtime due to associated equipment failures or operational difficulties encountered with the alternate coal feedstock. The following represents some specific equipment and operational issues encountered and resolved in 1999.

Slurry Mixers: Slurry mixers continue to be a source of downtime due to the corrosive/erosive nature of the slurry (and slurry/oxygen mix) and efforts continued throughout 1999 to improve the design and operation of these units.

Testing conducted in the first quarter on scale model mixers resulted in a new mixer design that was installed in the gasifier during the second quarter. Limited operating data from the second quarter indicated acceptable gasifier performance from the new mixers by increased cold gas efficiency and lower carbon content in the slag. By the end of the third quarter the new mixers exceeded expectations by accumulating over 1,800 coal hours with no evidence of degraded performance. In October, after approximately 1,980 hours of operation, the re-designed mixer failed due to thermal stress in the metallic mixer face. The geometry of future mixer faces will be modified to relieve some of the stress and the metallurgy of the mixer face will be upgraded to better resist stress cracking.

Slag Grinders: A two phase slag grinder system is mounted in series to the bottom of the quench reactor. A slag stream consisting of a 95% water and 5% slag passes through the grinders as it leaves the quench section. The first grinder crushes the slag to approximately 2.0 inches in diameter. The second grinder completes the crushing of the slag into approximately 0.5 inch diameter particles. The second grinder in series has an adjustment mechanism to compensate for wear, thus controlling the final slag particle size. During 1999 several mechanical difficulties were identified in the system which led to plant downtime and are described below:

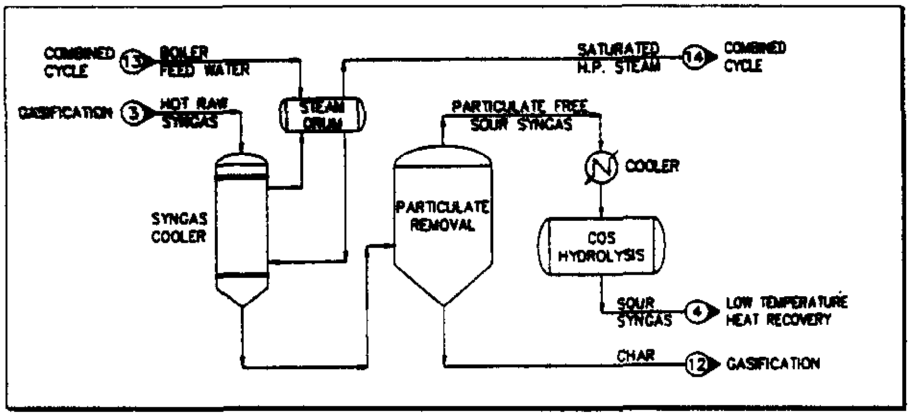
- During the first quarter, a slag grinder motor trip resulted in a transfer off of coal operations. The root cause of the problem was identified as reversed wiring of the upper grinder motor causing it to run backwards. (It should be noted that the grinders were able to handle normal slag flow and did not cause down time until fallen refractory brick from the gasifier bridged the grinder and prevented slag from exiting the gasifier.) The grinder was rewired to ensure proper rotation and put back into operation.

- Slag grinder packing leaks resulted in 2.5 days of downtime in August. A manufacturer applied (owner specified) coating on the grinder shafts was found to be incompatible with the shaft metal, which caused the coating to break loose from the shaft and begin cutting into the packing. A packing pump was installed in early August but it gradually became unable to maintain an adequate seal. Subsequently, an additional packing ring was installed over the existing stuffing box, which minimized leakage so that operations could continue safely without excessive packing addition. Due to the time required to facilitate a shaft replacement, a suitable coating will be applied to the grinder shaft when the on-line reactor is taken out of service for re-bricking in 2000. The grinder shafts for the off-line reactor have been re-coated with the proper material to ensure that this problem does not recur when the off-line reactor is placed back in service.

- In late December, the lower slag grinder began experiencing packing leaks similar to those encountered above. The addition of an auxiliary packing ring installed over the stuffing box was not successful in stopping the leak. To properly repair the leak required 42 hours of downtime to add larger packing to the stuffing box. The root cause of this failure was identified as inappropriate coating on the grinder shaft identical to the failures experienced in the upper grinder.

Tap hole Plugging: The "tap hole" refers to the transition opening located in the center of the horizontal section of the gasifier that allows slag to flow into the slag quenching section. Plugging becomes a problem when characteristics of the slag change, which affect the ability of the non-gasified portion of the coal to flow as a liquid. Operations were terminated in January due to plugging of the gasifier slag taphole. The cause of the taphole plug was related to a batch of coal with abnormally high ash fusion temperature. Increased lab analysis of the slurry fed to the gasifier have been implemented in an effort to catch feed abnormalities and respond more quickly in the future. Improved guidelines relative to the gasifier operating temperature have also been implemented.

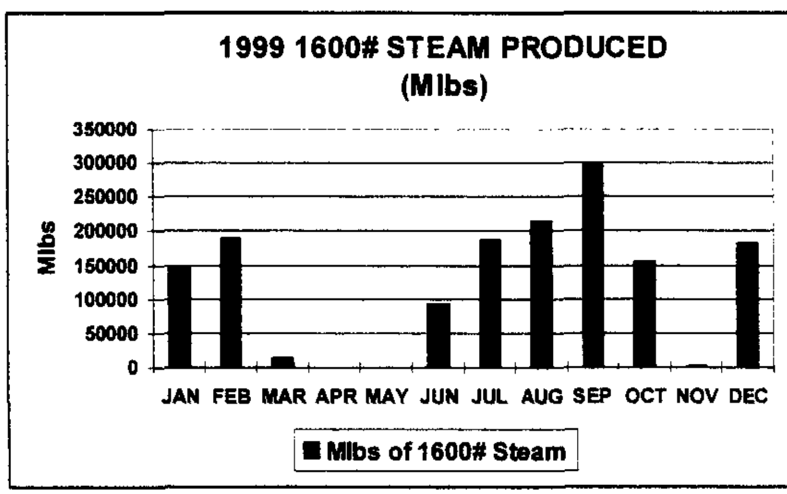
SYNGAS COOLING, PARTICULATE REMOVAL AND COS HYDROLYSIS



The gas and entrained particulate matter stream exiting the gasifier system is cooled below 1900 degrees F in a firetube heat recovery boiler system where saturated high pressure steam is produced. Steam from this High Temperature Heat Recovery Unit (HTHRU) is superheated in the HRSG for use in power generation.

The raw gas leaving the HTHRU passes through a barrier filter unit to remove particulates. The recovered particulates are recycled to the first stage of the gasifier. The particulate free gas is cooled further before proceeding to the carbonyl sulfide (COS) hydrolysis unit.

COS is present in the hundreds of ppm concentration range and is not removed as efficiently as hydrogen sulfide (H_2S) by the Acid Gas Removal (AGR) system. In order to obtain a high sulfur removal level, the COS is converted to H_2S before the sour syngas enters the AGR. This is accomplished by catalytic reaction of the COS with water vapor to create H_2S and carbon dioxide (CO_2). The H_2S formed is removed in the AGR section and the majority of the CO_2 continues on with the raw syngas to the turbine.



Steam production, as shown in the graph at right, tracks the operational run history of the gasifier. Total 1600 psig steam production for 1999 was approximately 1,481 million pounds. This figure represents a production decrease from approximately 2,213 million pounds in 1998 due to the loss of the combustion turbine late in the first quarter. Additionally, production figures were low in November due to a planned plant outage and a failure of a recirculation line (and subsequent syngas fire) to the dry char filtration system, which caused significant damage to the electrical circuitry on the main gasifier structure.

Operational difficulties and opportunities for improvement identified in 1999 will be broken down into the primary processes in this system. The three primary processes are identified as: HTHRU, particulate removal (dry char), and COS hydrolysis. Each component of this system is critical to the overall production capability of the gasification process. The following major events effected overall operation of this system in 1999:

HIGH TEMPERATURE HEAT RECOVERY UNIT (HTHRU)

HTHRU fouling continues to be a problem. Extremely hard material deposited in the tubes has reduced boiler efficiency. Hydro-blast units up to 40,000 psi have been unable to remove the fouling in a reasonable amount of time. Mechanical cleaning of the boiler accounted for approximately 336 hours of downtime during the year.

During the extended outage following the combustion turbine failure in March, a new process to mechanically clean the boiler tubes was developed. The new process utilizes core drilling bits and apparatus that were developed at the site. The new method restored the boiler tubes to "like-new" condition within a reasonable time. The outlet temperature of the boiler, when returned to operation, was approximately 20-40°F lower than it has been in the last two years, which is an indication of significantly improved heat transfer. The lower temperature should reduce the corrosion rate of the downstream metallic dry char filter elements and appears to have decreased the filter-blinding rate as well. Reduction of the boiler inlet temperature has reduced the fouling rate. Current projections indicate that six months of runtime can be achieved before process side boiler cleaning is required.

During the October outage, the waste heat boiler tubes were re-cleaned to "like-new" condition. Emphasis has been placed on optimizing the cleaning process. Approximately 8 days of downtime was attributed to the cleaning of the tubes.

PARTICULATE REMOVAL (DRY CHAR FILTRATION)

The dry char recycle system is used to remove fine char and ash from the syngas stream and recycle it back to the first stage of the gasifier. In the recycle process, raw syngas (with entrained char and ash) first enters two parallel primary filters at a temperature of approximately 700 degrees F. The char is filtered as it flows vertically through tubular filter elements contained within the primary vessels. The char and ash form a cake on the exterior surface of the filter, which is periodically back-pulsed with high-pressure syngas, dislodging the cake from the filter. It then drops by gravity to the bottom of the conical-shaped outlet of the filter unit where it is drawn from the vessel and recycled back to the gasifier. Past performance of this system has indicated that inlet temperature, char loading, back-pulse gas temperature, and composition and design of the filter elements play critical roles in the operation of this system. In 1999 the dry char system accounted for approximately 12.9% of total facility downtime (772 hours) due to the failure of the inlet line and char breakthrough in the system because of a ceramic element failure. 1999 hours are significantly higher than the 1998 total of 180 hours and slightly higher than the total 1997 hours of 706.

The following key areas of operation and mechanical malfunction were responsible for the majority of the downtime for 1999:

- During the first quarter, failure of a ceramic filter element in the particulate removal system resulted in a plant shutdown and nearly two weeks of downtime. During the December 1998 outage a test cluster of externally fused ceramic filters (previously tested successfully in the slipstream unit) was installed in one of the primary char vessels. A defect in the element support hardware (washer out of tolerance) resulted in a premature failure of one of the filter elements. The external fuse had also failed resulting in excessive solids loading in the downstream low temperature heat recovery unit and the sour water system. The cause of the fuse failure is under investigation with the manufacturer.

- During the October outage, high wear areas of the dry char recycle piping were replaced with an upgraded erosion-resistant material. Shortly after returning the unit to coal operations in November, a failure occurred in one of the new segments of erosion resistant pipe, which resulted in a syngas leak. The leak ignited and the subsequent fire caused damage to an adjacent cable tray. The cause of the piping failure was traced to pieces of polyvinyl chloride left in the piping by the manufacturer during installation of the lining. The material decomposed at process temperatures and resulted in excessive and rapid chloride stress corrosion cracking of the piping. Subsequently, all of the recently installed piping was replaced with new piping in which tighter quality control of the manufacturing process was exercised, including having a Dynegy representative personally witness the assembly of the piping. Approximately 18 days of downtime resulted from the failure and replacement of burned instrument wiring and cable tray.

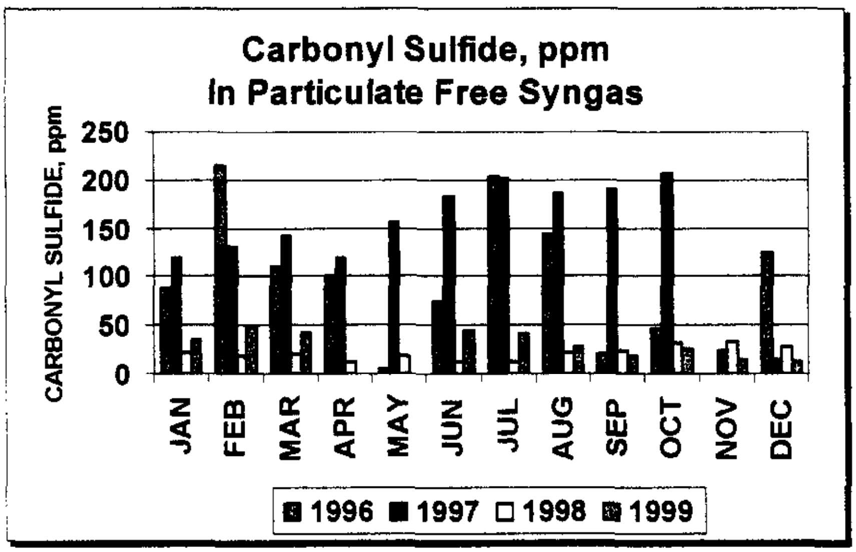
Key positive indicators of dry char performance during 1999 include:

- The dry char ejector performance remains strong. New material for the motive gas nozzles continues to excel, as the ejectors have shown no evidence of degraded performance since their installation in 1998.

- The dry char filter-blinding rate during the initial campaign after the combustion turbine outage was exceptional. Projections based on third quarter data, with the current feedstock, indicate that filter life (limited by blinding) could exceed 6,500 hours compared to our previous best projection of only 3000 hours. The blinding rate of the char filters increased some in late September, which was attributed to the pet coke test. During the pet coke test, the char filters were subjected to approximately 100% more char loading which may have resulted in some element bridging. This bridging can be avoided during future petcoke operation by increasing the frequency of back-pulsing the candle elements.

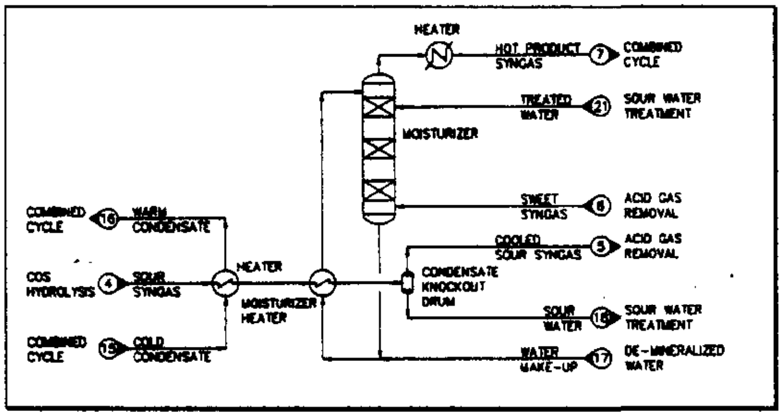
CARBONYL SULFIDE HYDROLYSIS

The primary purpose of the carbonyl sulfide (COS) hydrolysis unit is to convert COS to H_2S. COS cannot be effectively removed from downstream processing and must be converted to H_2S to facilitate removal in the amine process. Conversion and subsequent removal of the COS results in lower total reduced sulfur (TRS) in the product syngas and lower sulfur dioxide emissions from the combustion turbine exhaust stack.



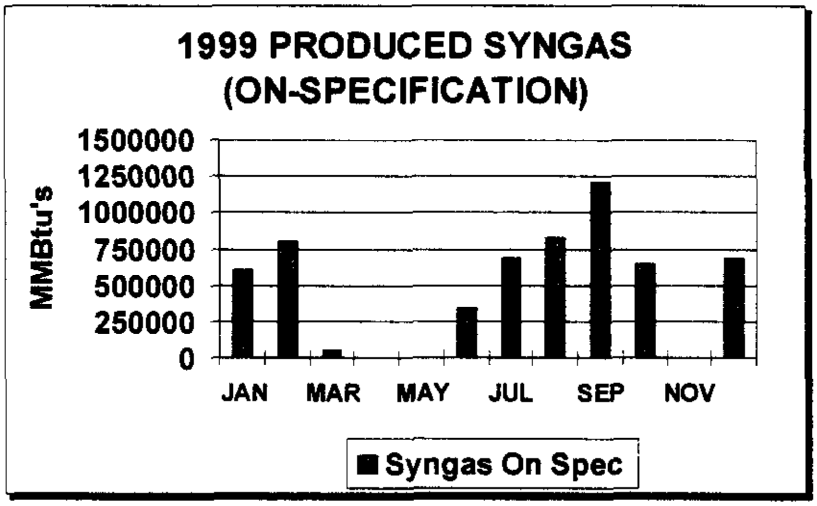
The chart at left depicts ppm levels of COS on a comparative basis between 1996, 1997, 1998 and 1999. As is illustrated by this graph, significant progress has been made in the control of COS from the hydrolysis unit and in operating the system on a more consistent basis. In 1996 the average ppm level of COS leaving the hydrolysis unit was 102.9 ppm, while the 1997 average increased to 139.4 ppm. These high values were due to catalyst contamination by arsenic and chlorides in 1996 and to partial degradation in 1997, resulting from a deflagration incident which reduced the total surface area of the catalyst and promoted channeling through the reactor bed. 1998 reflects the first year of optimum operation, as is indicated by an average value of 26.78 ppm of COS in the product syngas. This was achieved following catalyst bed replacement in the fourth quarter of 1997, and illustrates the capabilities of this unit when it is properly operated and maintained. 1999 continues this trend with an overall average of 26.18 ppm. Proper upstream operation of equipment has prevented contamination of the catalyst system and the unit has stabilized operation with very little degradation of the carbon support system or catalyst. By emphasizing upstream control of contaminants (char and chlorides) in the syngas, operation and maintenance of the COS hydrolysis unit has been of minimal concern in 1999.

LOW TEMPERATURE HEAT RECOVERY AND SYNGAS MOISTURIZATION



After exiting the COS hydrolysis unit, the remaining low level heat is removed from the syngas in a series of shell-and-tube exchangers located before the Acid Gas Recovery (AGR) system. This cooling condenses water, ammonia, carbon dioxide, and some hydrogen sulfide (H_2S) which produces sour water. The sour water is collected in the condensate knockout drum and sent to the sour water treatment unit. The heat removed prior to the AGR system provides moisturizing heat for the product syngas, steam for the AGR H_2S stripper, and condensate heat.

Cooling water provides trim cooling to ensure the syngas enters the AGR near its design temperature (approximately 100 degrees F). The cooled sour syngas is fed to an absorber in the AGR system where the solvent selectively removes H_2S to produce a sweet syngas low in total reduced sulfur. The sweet syngas is then moisturized to a water content of approximately 22%, by volume, using low level heat from raw syngas cooling. Moisturization is accomplished by contacting the sweet syngas and hot water counter-currently in a high surface area contacting column. After the moisturizer, the syngas is preheated before being directed to the combustion turbine. Moisturization and preheating of the syngas increases efficiency in the combustion turbine and reduces the steam requirement for NO_x control.



Sweet syngas (product syngas) production for 1999 totaled 5,813,151 MMBtu's with the highest production occuring in the third quarter. This can be compared to a 1998 production of 8,857,869 MMBtu's. Severely impacting production for 1999 was the unplanned turbine outage between March and June. Additionally, failure of the newly installed dry char recirculation line in November impacted production in the fourth quarter. On a more positive note, third quarter syngas production exceeded all previous quarterly results by producing the most syngas in a quarter (2,712,107 MMBtu's) and more than doubling the previous continuous hours-on-coal record by operating 1,304 hours. Sweet syngas moisturization operated efficiently and provided a consistent product gas moisture content of approximately 20%-23% throughout 1999. Product syngas quality remained high and will be discussed later in this section.

The LTHRU contributed a total of 10 hours of plant downtime in 1999 (compared to 7 hours in 1998) when an unused tubesheet spray nozzle on an exchanger in the low temperature heat recovery section of the plant was removed after a piping failure caused a brief release of syngas. The piping failure was due to chloride stress cracking that developed prior to installation of the chloride scrubber in 1996.

PRODUCT SYNGAS QUALITY: Product syngas quality remained consistent throughout 1999. Miller Creek coal and petroleum coke had virtually no effect on the quality of the product syngas when compared to the Hawthorne feedstock. Please note that the average values indicated below do not include the averages for April, May, and November due the plant shutdowns during those months.

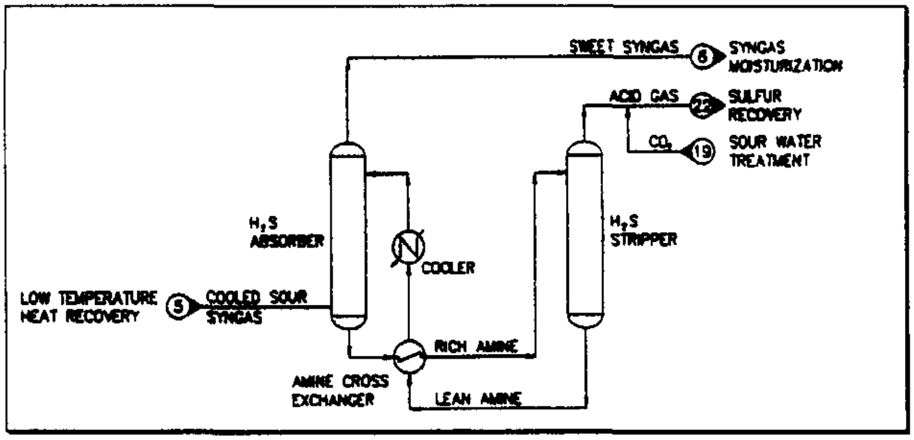
> **Hydrogen Content**: Hydrogen content (dry weight-percent) in the syngas varied from an average monthly low of 32.21% in March to a high of 33.44% in October. Average concentration for hydrogen in the product syngas for 1999 was 32.66%
>
> **Carbon Dioxide Concentration**: Carbon dioxide (dry weight-percent) in the syngas varied from an average monthly low of 15.25% in January to a high of 16.22% in October. Average concentration for carbon dioxide in the product syngas for 1999 was 15.75%.
>
> **Carbon Monoxide Concentration**: Carbon monoxide (dry weight-percent) in the syngas varied from an average monthly low of 44.44% in August to a high of 46.31% in March. Average concentration for carbon monoxide in the product syngas for 1999 was 45.52%.

Methane Content: Methane (dry weight-percent) in the syngas showed a slight variability throughout the year. A low value of 1.88% was recorded in July with a high of 2.17% being recorded in February. Average concentration for methane in the product syngas for 1999 was 1.99%.

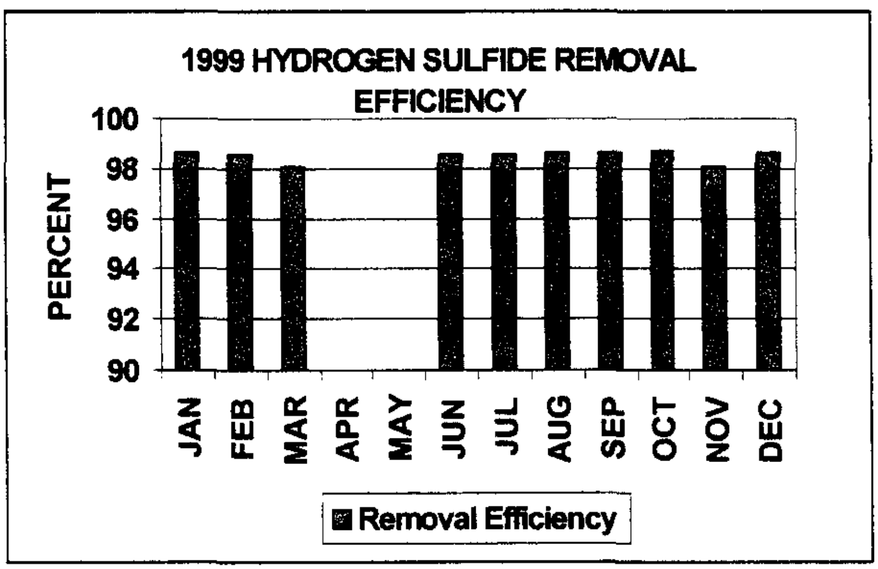
Hydrogen Sulfide Concentration: H_2S concentration (ppm) in the product syngas is a direct result of the operational characteristics of the Acid Gas Removal System (AGR). Variability can be directly attributable with system performance in that system throughout the year. A high value of 106.03 ppm was recorded in September while a low value of 86.32 ppm was recorded in October. Average concentrations of hydrogen sulfide for 1999 was 95.98 ppm.

Carbonyl Sulfide Concentration: COS concentration (ppm) in the product syngas shows an expected low variability when compared to previous reporting periods. The COS hydrolysis unit operated more efficiently during 1999 when compared to previous years. COS in the product gas recorded an average high value of 24.22 ppm in February and an average low value of 11.36 ppm in December. The average value for COS in the product gas for 1999 was 15.92 ppm.

ACID GAS REMOVAL



The first step in the sulfur removal and recovery process is the Acid Gas Removal (AGR) system, which removes the hydrogen sulfide (H_2S) present in the sour syngas. The AGR system also produces a concentrated H_2S stream (acid gas) that is fed to the Sulfur Recovery Unit (SRU). The AGR system is a totally contained system and does not produce emissions to the atmosphere. H_2S is removed in the absorber using an H_2S solvent, methyldiethanol amine (MDEA). The H_2S rich solvent exits the absorber and flows to a reboiled stripper where the H_2S is steam stripped at low pressure. The concentrated H_2S stream exits the top of the stripper and flows to the SRU. The lean amine exits the bottom of the stripper and is cooled, then recycled to the absorber.



Hydrogen sulfide removal efficiencies remained fairly consistent throughout 1999 as can be seen by the chart at right. The efficiency calculation uses total combustion turbine stack and flare stack syngas emissions (as sulfur) compared to the total sulfur feed to the gasification plant (sulfur, dry-weight percent) for the most conservative estimate of performance.

The following is a brief summary of the 1999 operational campaign in the AGR system. Variability in operation and significant factors effecting downtime are as follows:

- During the first quarter 22 hours of outage time was attributable to the AGR system. During plant start-up on January 5, the pressure test was delayed while operations investigated and identified a pressure safety valve discharge point. Moisture had condensed and frozen in the pilot sensing line for this PSV, causing the valve to relieve significantly below the relief set point. The PSV is overpressure protection for the column responsible for the removal of H_2S from the syngas. Additional insulation and heat tracing have been applied to this valve to reduce the probability of a repeated incident.

- The H_2S removal efficiency for the third quarter increased slightly from the second quarter average of 98.5%. This increase in removal efficiency is more attributable to the increased run length than any specific improvement in plant operation. With the increased run time in third quarter, the upset conditions surrounding start-ups and shutdowns constitute a smaller fraction of the total run time. Consequently, the removal efficiency appears to have increased.

Heat Stable Amine Salts (HSAS):

The most significant impact on AGR system performance in 1999 was project improvements associated with the Ion Separation (ISEP) unit. Heat stable amine salts form when non-volatile acids react with amine irreversibly, meaning they are not stripped under the vapor heating in the stripping column. Typical HSAS compounds include formates, sulfates, thiocyanates, acetates, and oxalates. These salts accumulate within the amine over time, continually tying up (or binding) free amine thus the term "bound amine". Bound amine is not free to remove H_2S from the syngas and is typically corrosive to system components as the heat stable salts level increases.

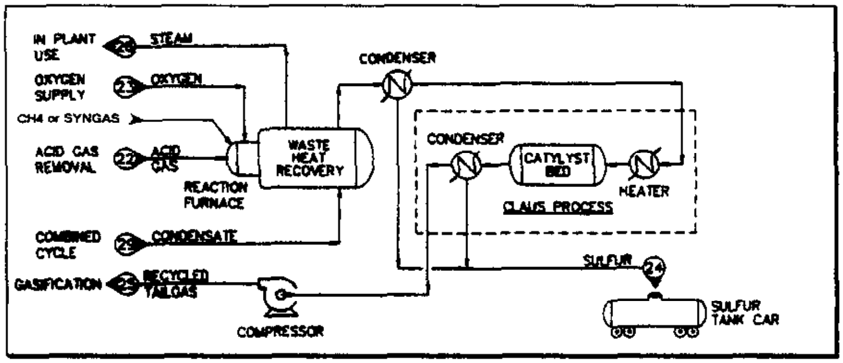
The ISEP is designed to process approximately one (1) percent of the total MDEA flow in the system and remove HSAS so that column performance can be maintained. The ISEP process can be defined as reversible exchange of ions between a solid and a liquid in which no substantial change in the solid's structure occurs. The plant has now achieved two years of operation without amine reclamation services. In the past, and in many gas-sweetening plants, amine solvent reclamation technologies such as vacuum distillation and dialysis have been employed to remove heat stable amine salts. The ISEP, an in-house ion exchange unit, has effectively eliminated the need for contracting these services for heat stable salt removal as demonstrated below:

- During the first quarter of 1999, final planning, purchasing and delivery of key components of the ISEP improvement project took place. The key components of the plan includes: a new (larger capacity) brine tank that can be loaded via bulk delivery; a larger capacity brine delivery pump; and newly designed resin canisters. These components, installed during the second quarter extended outage, will enable the ISEP unit to remove heat stable salts at the rate of formation eliminating the heat stable salt accumulation problem. The canister height was increased and the material of construction was changed from fiberglass to a metal alloy to increase mechanical integrity. The new brine tank and pump will provide more capacity to the brine squeeze zone of the ISEP unit, the current capacity limitation.

- Mechanical difficulties during start up of this system hindered optimization efforts and prevented an accurate evaluation of the capacity increase during the limited run time in the second quarter. After a change in the piping configuration and replacement of fouled resin, the expansion projects yielded dividends in the third quarter. The ISEP experienced an approximate 20% increase in heat-stable-salt removal capacity. With the removal rate now surpassing the rate of formation, the concentration of heat stable salts within the amine solution is now on the decline.

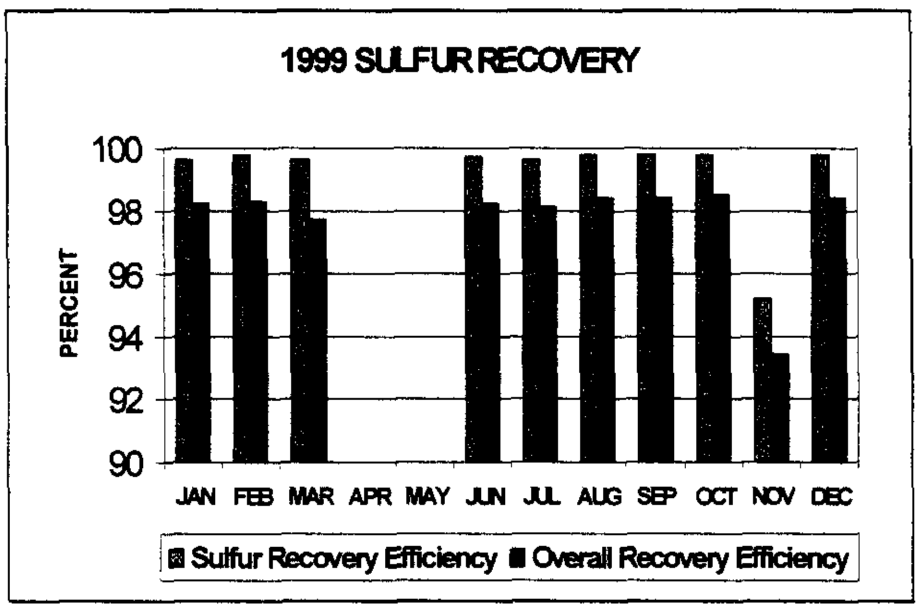
These improvements will reduce the operation and maintenance cost of the facility in two ways. First, the amount of amine purchased annually can be reduced. In the past, heat stable salt accumulation deteriorates the performance of the amine plant, necessitating the purchase of new amine solution. This additional amine solution effectively reduces the concentration of heat stable salts allowing the plant to continue operation. Now, amine should only need to be purchased to replace solution lost due to thermal degradation, blow-down of the regeneration column, and rinsing of the ISEP. The second cost reduction will come from the reduced need for amine reclamation. In the past, amine reclamation services were contracted to process our amine solution to remove all contaminates. Of these contaminates, heat stable salts constituted the vast majority. These services will now be utilized on a less frequent basis, if not eliminated entirely.

SULFUR RECOVERY



The concentrated H_2S stream from the acid gas removal system, and the CO_2 and H_2S stripped from the sour process water, are fed to a series of catalytic reaction stages where the H_2S is converted to elemental sulfur. The sulfur is recovered as a molten liquid and sold as a by-product. A tailgas stream, composed of mostly CO_2 and N_2 with trace amounts of H_2S, exits the last catalytic stage.

The tail gas from the Sulfur Recovery Unit (SRU) is hydrogenated to convert all the sulfur species to H_2S, cooled, compressed and then directed to the gasifier. This allows for a very high sulfur removal efficiency with minimal recycle requirements. Provisions in the system will allow for final treatment of the tail gas in the tail gas incinerator. A tank vent stream is also treated in the incinerator. The tank vent stream is composed of air purged through various in-process storage tanks and contains very small amounts of acid gases. The high temperature incinerator efficiently destroys the H_2S remaining in the stream by converting it to SO_2 before the exhaust gas is vented to the atmosphere from a permitted air emissions source.



Sulfur recovery efficiencies indicated at left are split into two specific areas. The blue columns indicate the efficiency of the SRU by comparing total stack emissions with total sulfur feed to the SRU. *Overall Plant removal efficiencies* (green columns) compare total joint venture emissions (as sulfur) verses total sulfur feed to the gasifier.

Minor variations in SRU sulfur recovery efficiencies during the 1999 operational year are explained as follows:

- Like the H_2S removal efficiency, the first quarter overall recovery efficiency remained unchanged from the fourth quarter average of 98.2%. Operating personnel have continued to optimize the Claus reaction furnace by decreasing the amount of supplemental fuel firing. This reduces the cost of operation of the furnace and increases the efficiency of the catalyst beds within the SRU.

- During 1Q99, 8 hours of outage time was attributed to the SRU. During a plant start-up on March 11, prior to acid gas addition to the SRU, combustion products from the Claus reaction furnace were released from a sulfur seal leg. The subsequent investigation concluded that the combination of a vacuum downstream and normal controlled pressure upstream was sufficient to clear the seal leg. The vacuum was created while pumping down the liquid sulfur storage tank. The normal pressure control set point for the SRU during outages has been reduced to avoid any recurrence of this incident.

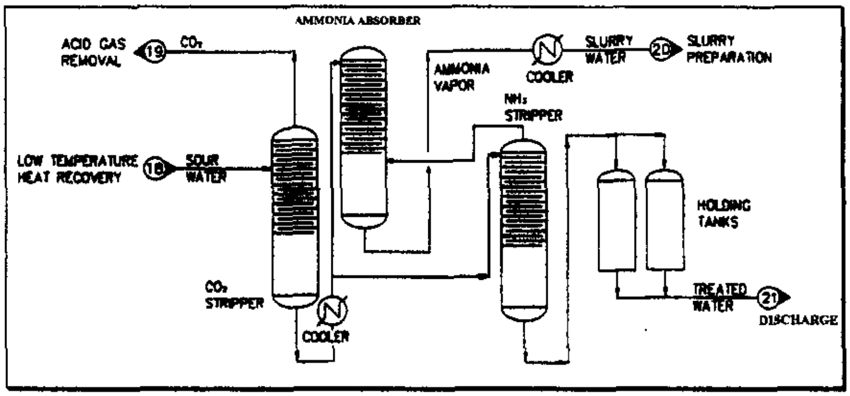
- Both the SRU sulfur recovery efficiency and the overall sulfur recovery efficiency for 3Q99 increased slightly from the 2Q99 averages of 99.7% and 98.2%, respectively. Much credit for this increase can be given to continuous operation of the plant. However, the SRU received the highest average acid gas concentration of any previous quarter in 3Q99. Because the Modified-Claus process is a series of equilibrium driven reactions, higher acid gas concentrations increase the driving force for the formation of elemental sulfur, thereby increasing the single pass recovery efficiency. The increase in acid gas concentration is a result of lower amine circulation rates and higher sulfur feedstock to the gasifier such as Miller Creek coal and petroleum coke.

- On 7/12/99, the gasifier tripped due to slurry feed problems. Shortly after transferring back to coal operation, the SRU air demand analyzer, the instrument responsible for determining fine adjustments to the Claus furnace oxygen supply, experienced an undetected plug in the sample line. Hours later, the accumulating error in the air demand analyzer caused an elevated SO_2 concentration in the catalyst beds, necessitating the addition of supplemental hydrogen in the tail gas hydrogenation reactor. When the hydrogen was added, the SRU pressure controller misinterpreted the signal from a pressure transmitter. The controller opened the SRU pressure control valve, by-passing the tail gas recycle compressors and allowing tail gas to flow to the tail gas incinerator. As a result, the SO_2 flow from the permitted tail gas incinerator stack reached a reportable level and coal operation was immediately suspended. Since this incident, the pressure controller has been modified to prevent a recurrence. Additionally, there is a project currently being implemented which will give operations an indication when the air demand analyzer signal is not reliable.

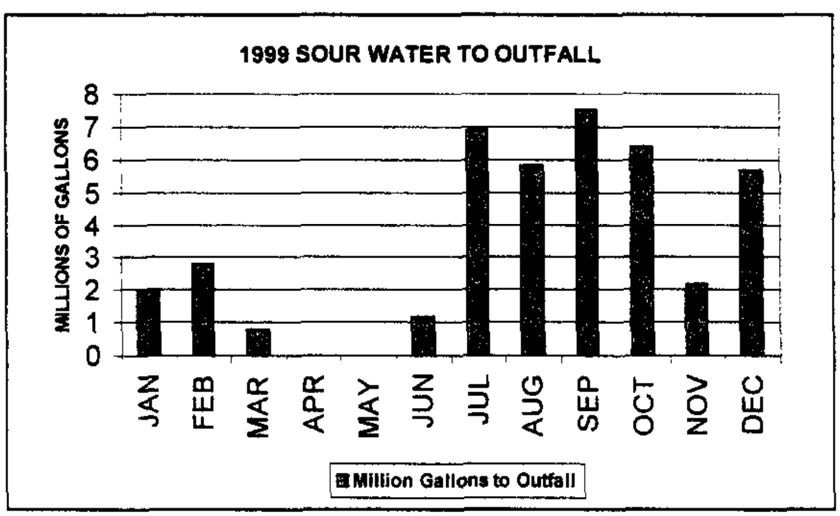
- The sulfur recovery efficiency for 4Q99 remained unchanged from 3Q99. However the overall recovery efficiency increased slightly from the 3Q99 value of 98.3%. This slight increase is likely attributable to the increase in acid gas feed concentration from the acid gas removal system, which resulted from cooler ambient temperature during 4Q99. The higher acid gas concentration resulted in a two-fold benefit for the sulfur recovery unit. First, the higher H_2S concentration in the SRU feed drives the equilibrium reaction on the Claus catalyst beds to shift towards products. The product in this case is the recovered elemental sulfur. Second, the higher acid gas concentration gives a higher BTU value feed to the Claus furnace, requiring less supplemental fuel firing to maintain the temperature necessary for proper contaminant destruction and formation of elemental sulfur via the disassociation reaction of H_2S.

- In early December, 69 hours of downtime were attributed to the sulfur recovery unit. On 12/9/99, it was determined that the hydrogenation bypass valve was damaged and failing to open completely. Upon inspection, it was found that a mass of material had accumulated against the valve, preventing it from opening. The valve then sustained damage when the actuator attempted to open the valve. The material was tested by x-ray diffraction and found to be a mixture of ammonium sulfate, iron sulfide, and elemental sulfur. The sulfur can be melted with current heat tracing but the other materials have higher melting points. How and why these other materials are present in this location are still being investigated but no clear solution to prevent recurrence of this incident has yet been identified.

SOUR WATER TREATMENT



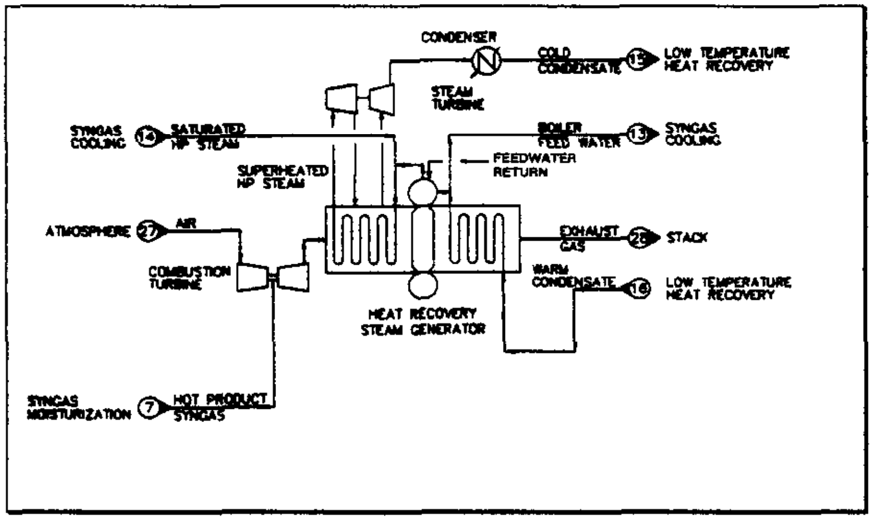
Water condensed during cooling of the "sour" syngas contains small amounts of dissolved gases, i.e. carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulfide (H_2S), and trace contaminants. The gases are stripped out of the sour water in a two step process. First the CO_2 and the bulk of the H_2S are removed in the CO_2 stripper column by steam stripping. The stripped CO_2 and H_2S are directed to the SRU. The water exits the bottom of the column, is cooled, and a major portion is recycled to slurry preparation. Any excess water is treated in the ammonia stripper column to remove the ammonia and remaining trace components. The stripped ammonia is combined with the recycled slurry water. The treated water can be directed to the moisturizer or discharged from the plant. Prior to discharge, the water passes through two activated carbon filters for further processing. If out of specification for discharge, the treated water can be stored in holding tanks for further testing or recycle to the sour water system. Discharge of this stream is controlled or regulated as a combined stream with PSI's plant discharge into the permitted water outfall pond.



As depicted at left, sour water to the outfall varied from a high in September of 7.2 million gallons to a low in April and May of 0.0. During the third quarter there was a short period of atypical operation. The lower slurry rates combined with the lower moisture content of the petroleum coke feed at the end of September caused the sour condensate conditioning unit to see approximately 40% less flow. Typically, this reduction in feed causes unfavorable hydraulics within the conditioning columns, resulting in the production of off-spec water. However, during this period, a process of false loading was employed. Using existing piping, conditioned water was transferred to the tail gas quench column and then back to the front of the sour condensate conditioning unit. In doing so, proper column hydraulics and in-spec water were maintained without upset or addition of supplemental water.

Specific information about the quality of the water to the outfall is covered under the 1999 Environmental Monitoring Plan Annual Report and can be used as an additional reference to provide more specific information about discharge quality.

COMBINED CYCLE POWER GENERATION



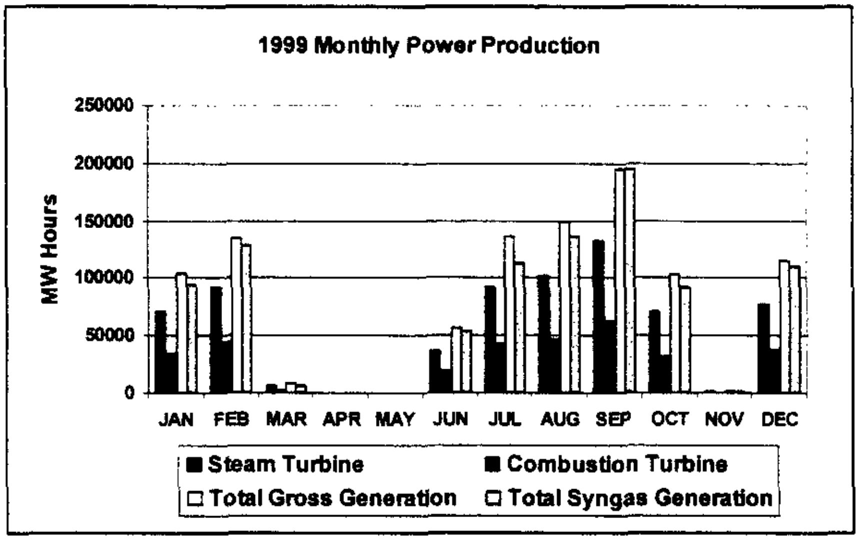
The combined cycle system consists of a combustion turbine generator, heat recovery steam generator (HRSG), reheat steam turbine generator, condenser, deaerator, flash drums, condensate pumps and boiler feedwater pumps.

The gas turbine (GT) is a nominal 192 MW advanced cycle combustion turbine fueled primarily by syngas. Fuel moisturization and steam injection control NOx emissions and increase power output. Combustion air is drawn through inlet filters from outside the building housing the gas turbine. Combustion exhaust gases are routed to the HRSG. No. 2 fuel oil is used as back-up fuel for the gas turbine during startup and shutdown, and for other periods when syngas is unavailable. Fuel oil is stored in tanks located within the existing plant.

The HRSG recovers heat from the GT exhaust gases to generate high-pressure steam. This steam, combined with steam from the syngas HTHRU, re-powers the Unit 1 reconfigured steam turbine. Steam generated in the HRSG is piped to and from the steam turbine through extensive piping additions. The HRSG receives GT exhaust gases and generates steam at 1600 psig and 1000 degrees F (main steam) and re-heats extraction steam from the steam turbine back to 1000 degrees F at about 750 psig extraction pressure (reheat steam). The HRSG is specifically designed for high operating efficiency and configured for horizontal flow through a series of vertical heat transfer modules. Design of the HRSG is optimized for a syngas-fired gas turbine.

The Wabash River Station Unit 1 steam turbine is located in the existing powerhouse. The steam turbine was originally supplied by Westinghouse and went into commercial operation in 1953 at a nominal rating of 99 MW.

The turbine was designed for reheat operation with five levels of extraction steam used for feedwater heating. To maximize efficiency, feedwater is heated in both the HRSG and the gasification plant. With the need for extraction steam from the steam turbine eliminated, the steam previously extracted passes through the steam turbine to generate 105 MW of power. As a result, minor modifications to the turbine steam path ensure acceptable steam path velocities. The generator and main power transformer continue to be used and have required only minimal modification.



As can be seen by the chart at left, the third quarter of 1999 produced the largest total power output for the year. The months of July, August, and September show back-to-back high peak months of operation, which has not been accomplished by the facility since beginning operation in 1995. Second quarter activities were severely curtailed when, on March 13, at approximately 16:20 hours, a vibration alarm was detected on the #1 turbine bearing seismic probe. The unit tripped approximately 6 minutes later from high exhaust temperature. Following investigation, it was determined that the compressor had failed. Cinergy decided at that time to inspect the machine due to the level of teardown required. The inspection for all components, except the compressor, indicated normal wear for the number of starts and run time on the machine. The turbine had experienced 412 starts and over 14,000 hours of operation prior to this failure.

The compressor failure actually occurred in the 14th stage stator blades and propagated downstream. Damage from the 14th stage downstream was catastrophic in nature and required complete replacement of all rotating and stationary material. Due to schedule considerations and opportunities to upgrade the compressor, PSI decided to purchase and install a new upgrade compressor from General Electric.

The unit was returned to service on June 12, 1999 and has run successfully since that time. With respect to the root cause of the failure, Cinergy is unable to comment at this time pending further investigations.

The following table illustrates production during 1999:

	1 QTR	2QTR	3QTR	4QTR	TOTAL
Combined Cycle Operating Hours On Syngas	**821**	**199**	**1,621**	**780**	**3,421**
Longest Continuous Run Hours On Syngas	**425**	**179**	**1,115**	**318**	
Maximum CT Output (MW)	**192**	**192**	**192**	**192**	
Maximum ST Output (MW)	**98**	**98**	**98**	**98**	
Total Gross Generation (MWHours) On Syngas	**229,814**	**54,052**	**444,364**	**203,713**	**931,943**

Budget Period 3 Activities

Budget Period 3 began on November 18, 1995. The costs shown reflect operational expenditures along with major process improvements implemented in 1999. Operations and systems data collected during the year will assist in the demonstration and commercialization of the technology.

	Revised Baseline Budget (per Cont. App. for Budget Period 3)	Actual Budget Period 3 Spending as of 12/31/99
Participant Share	$52,300,566	$64,032,578
DOE Share	$52,300,566	$48,898,439
Total	$104,601,132	$112,931,017

DOE Reporting and Deliverables

Spending and budget reports were submitted on both a monthly and quarterly basis according to the requirements of the Cooperative Agreement. Project reviews and Joint Venture quarterly reports were provided to the DOE. The following reporting requirements were submitted in accordance with Attachment C, sections 6 and 7 of the Cooperative Agreememt:

- Project Management Plan
- Environmental Monitoring Reports
- Operations Summary Reports

Other Activities

Several public relations and educational activities were carried out in 1999. Appendix C (Tab C) provides a list of selected public information and trade and technical papers presented by Dynegy or PSI personnel related to the WRCGRP.

APPENDIX A

Glossary of Acronyms

Appendix A
Glossary of Acronyms

ASU	-	Air Separation Unit
CAAA	-	Clean Air Act Admendments
CCT	-	Clean Coal Technology
CGCC	-	Coal Gasification Combined Cycle
COS	-	Carbonyl Sulfide
DOE	-	Department of Energy
EPA	-	Environmental Protection Agency
FAA	-	Federal Aviation Administration
GT	-	Gas Turbine
HHV	-	Higher Heating Value
HRSG	-	Heat Recovery Steam Generator
HTHRU	-	High Temperature Heat Recovery Unit
HSAS	-	Heat Stable Amine Salts
IDEM	-	Indiana Department of Environmental Management
IGV	-	Inlet Guide Vane
ISEP	-	Ion Separation unit
LGTI	-	Louisiana Gasification Technology, Inc.
LTHRU	-	Low Temperature Heat Recovery Unit
NEPA	-	National Environmental Policy Act
NPDES	-	National Pollutant Discharge Elimination System
P&ID	-	Piping and Instrument Drawings
PMP	-	Project Management Plan
PON	-	Program Opportunity Notice
SRU	-	Sulfur Recovery Unit
WRCGRP	-	Wabash River Coal Gasification Repowering Project

APPENDIX B

List of Figures

Appendix B
List of Figures

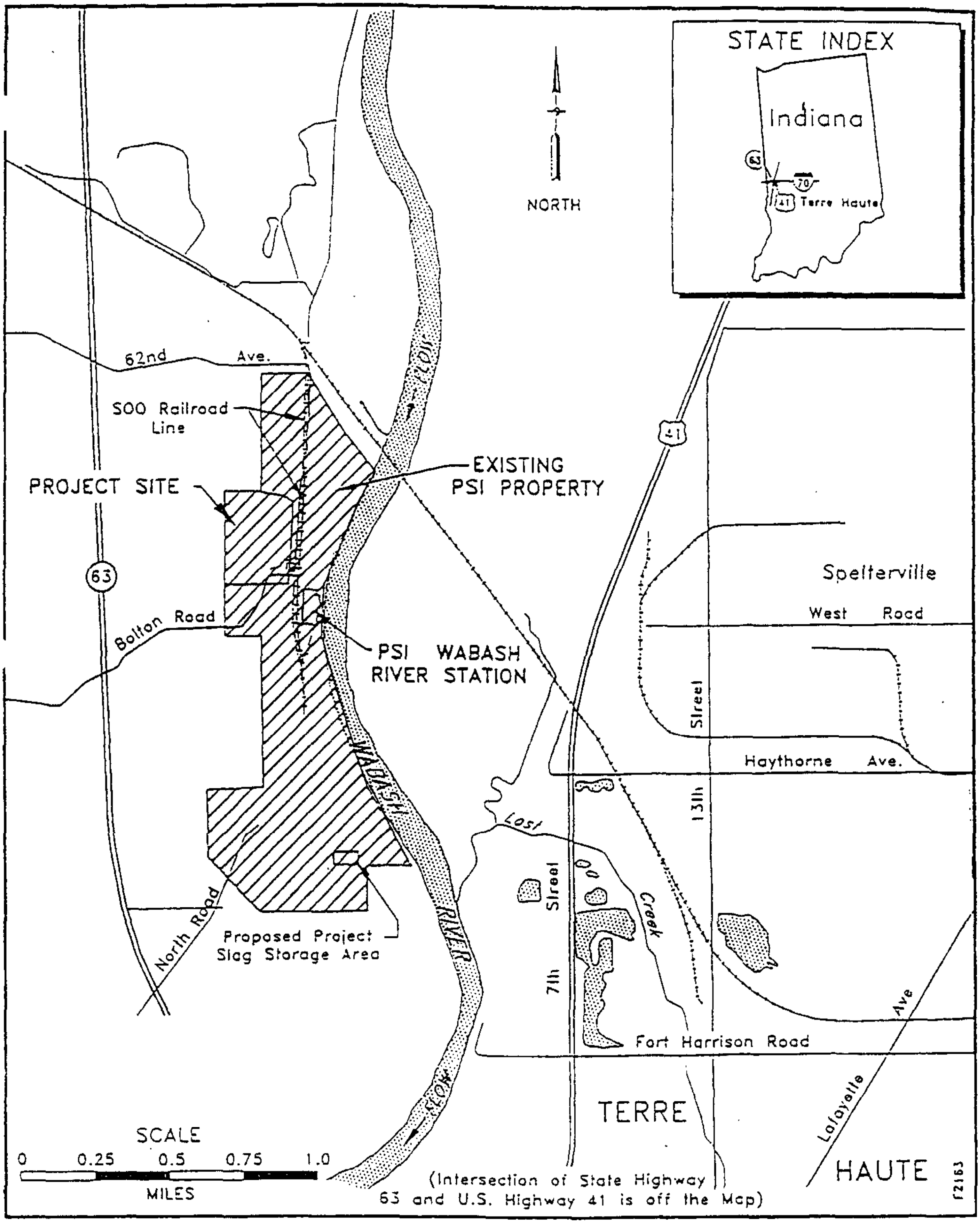


Figure 1 General Location Map Showing the Site of the Project

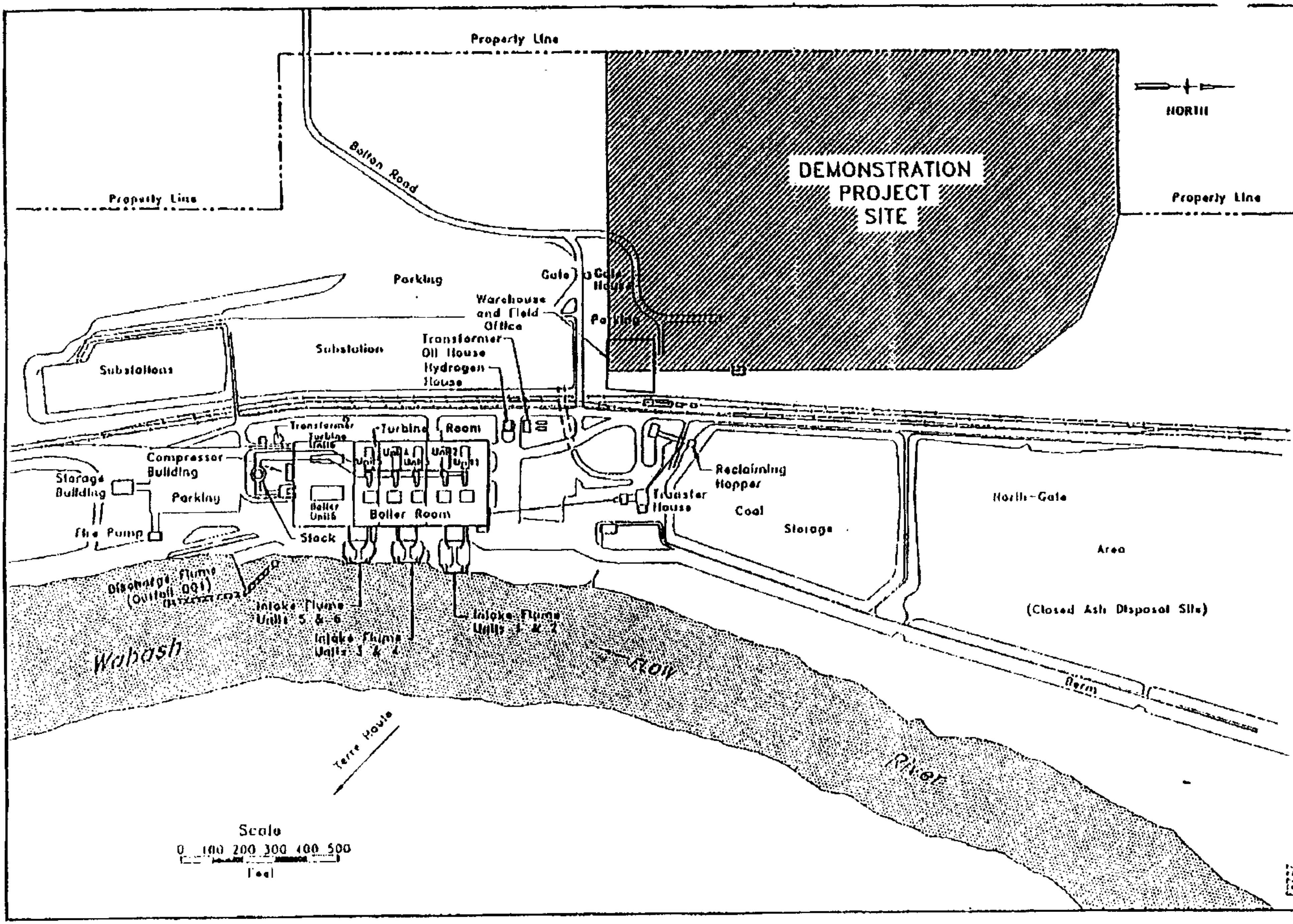


Figure 2 Site Map of the Wabash River Generating Station

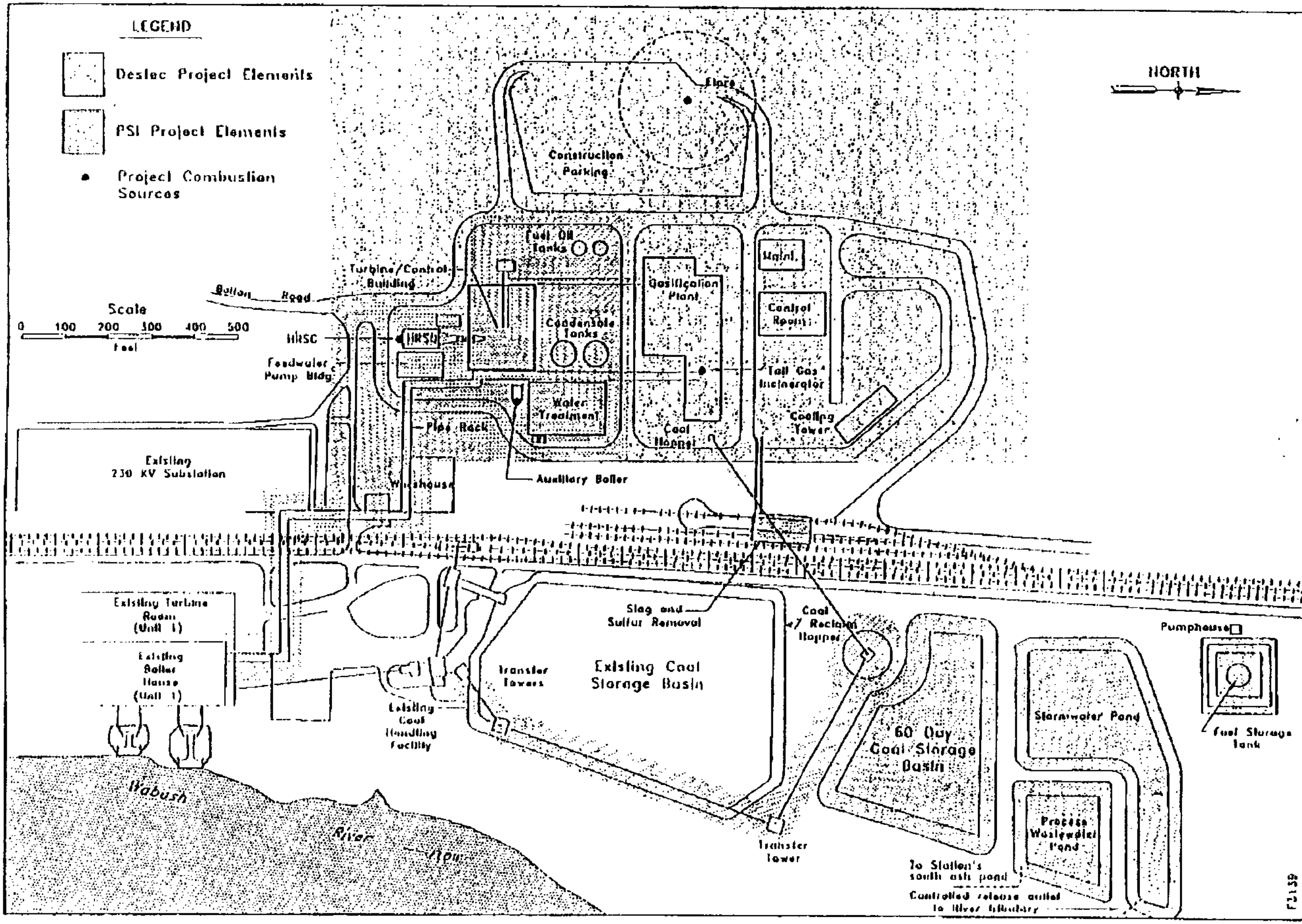


Figure 3 Project Plot Plan

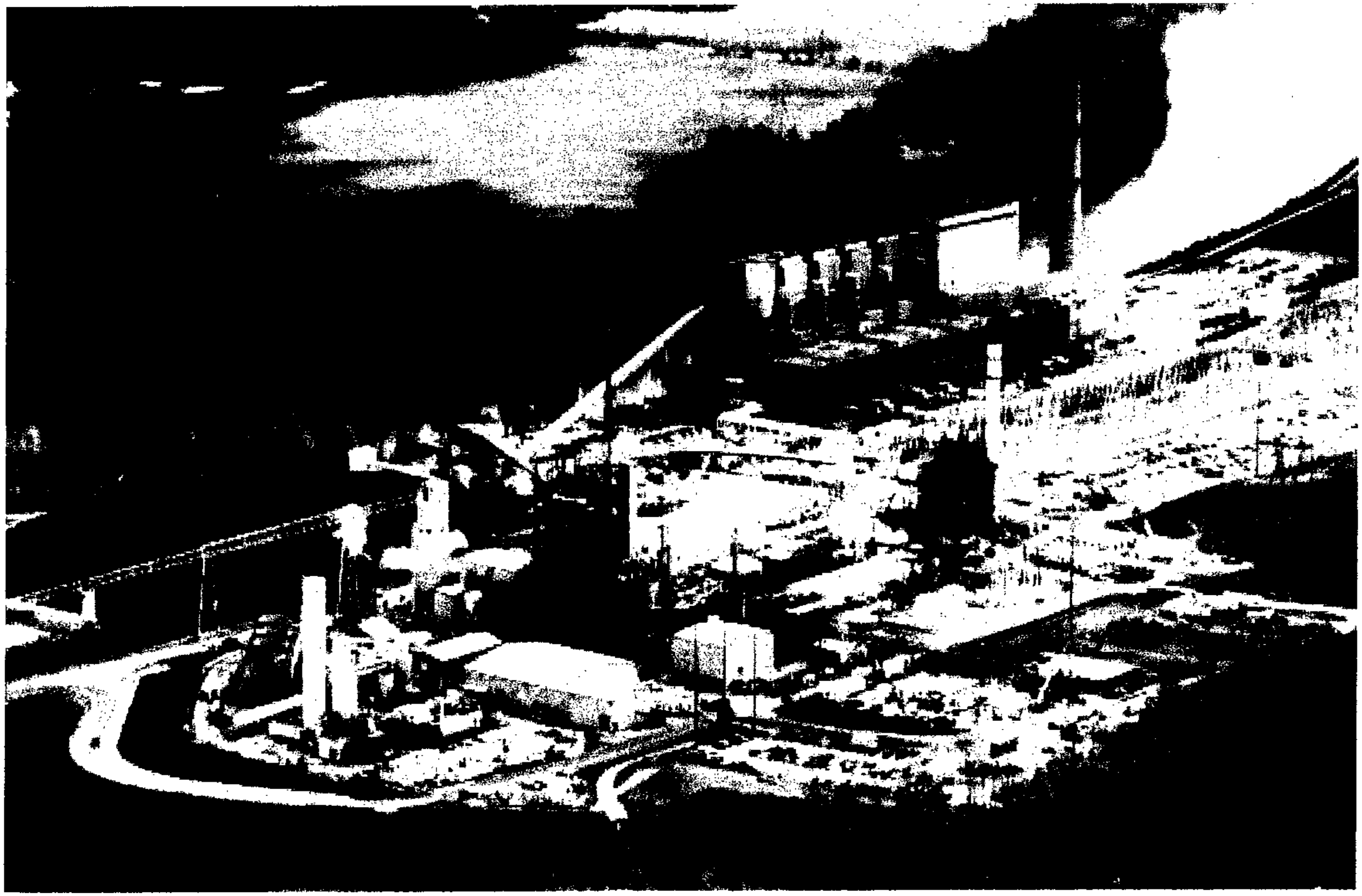


Figure 4

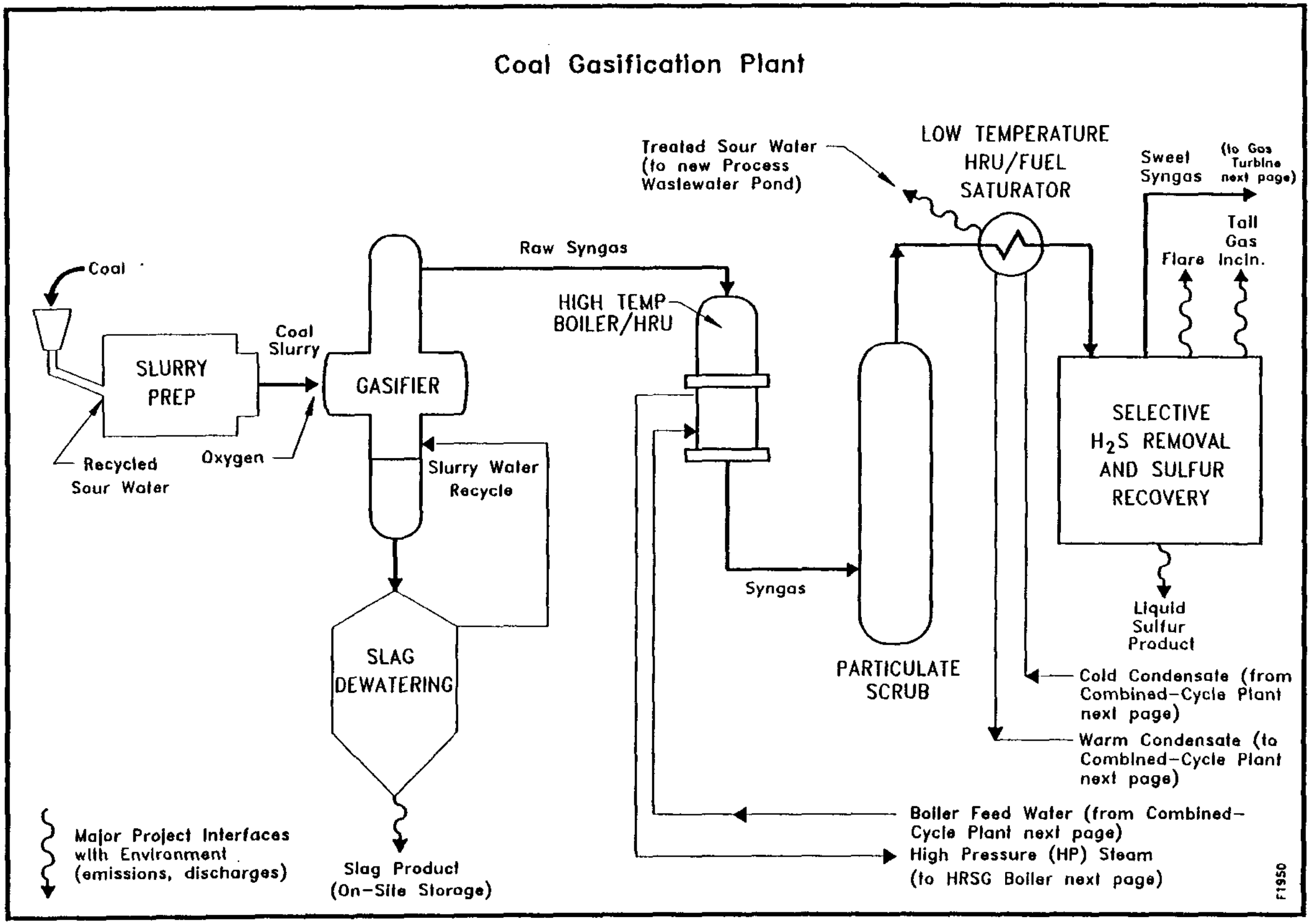


Figure 5 Conceptual CGCC Process Schematic

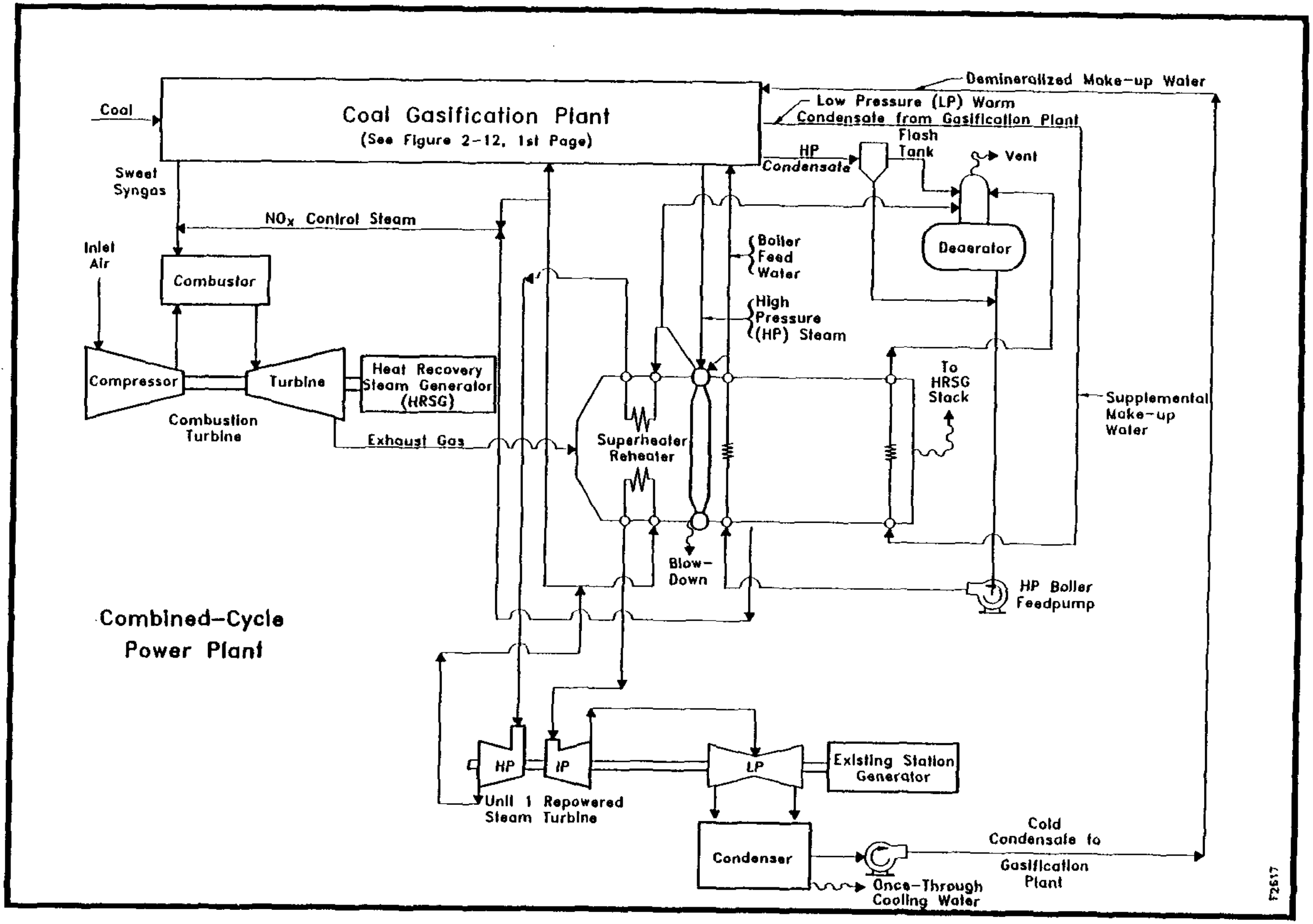


Figure 5A (Continued)

Block Flow Diagram

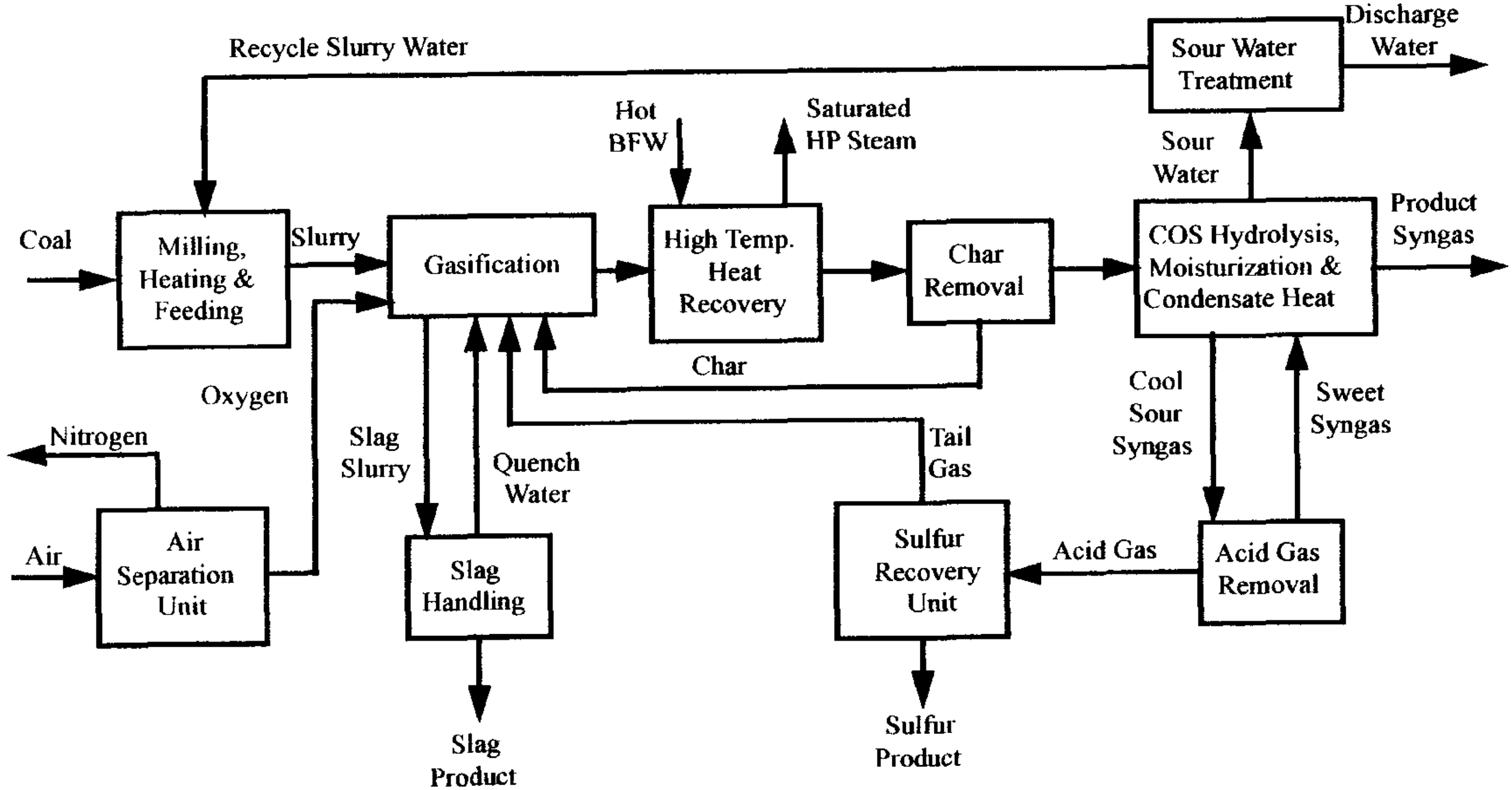


Figure 6 – Block Flow Diagram

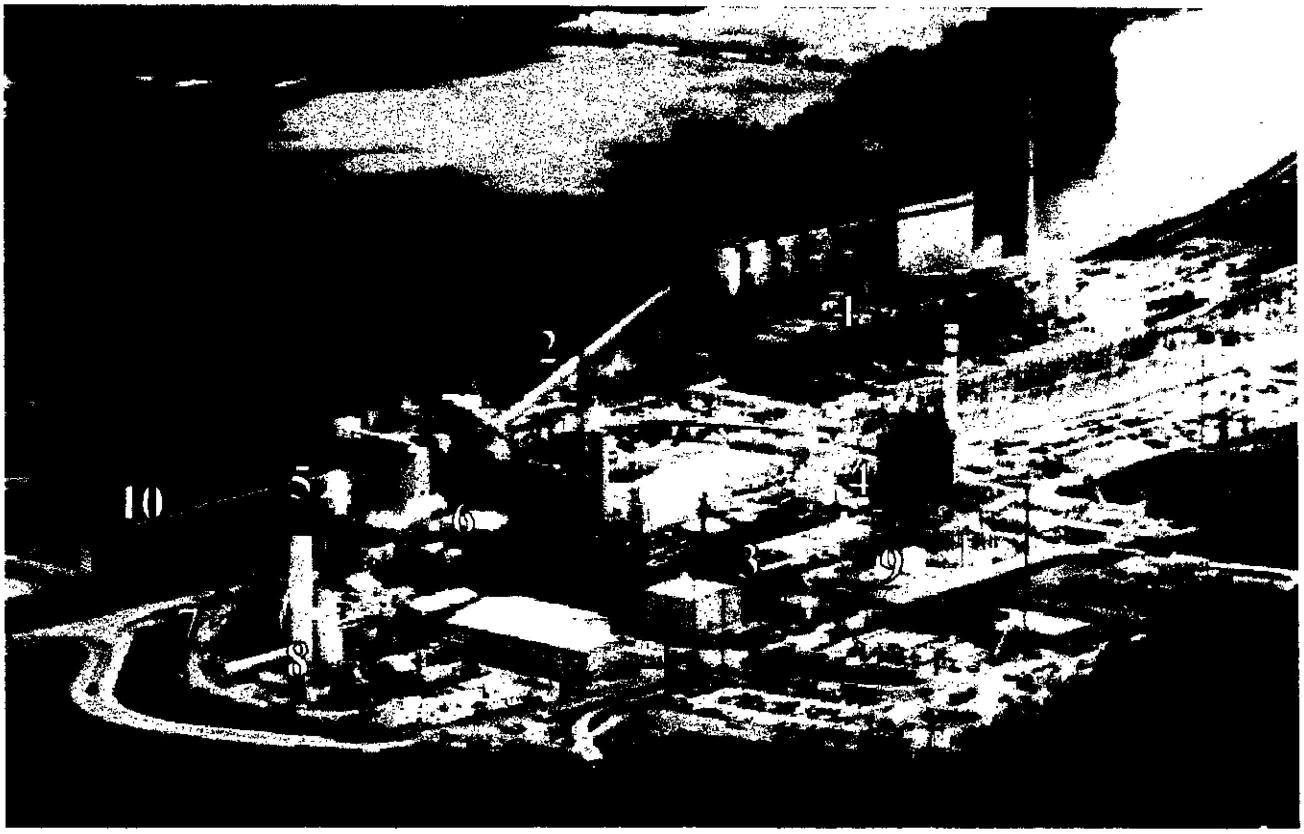


Figure 7

1. Existing Wabash Station
2. Existing coal transfer tower
3. Gas turbine building
4. Heat recovery steam generator
5. Coal receiving silo
6. Gasifier
7. Cooling Tower
8. Oxygen plant
9. New substation
10. Existing coal pile

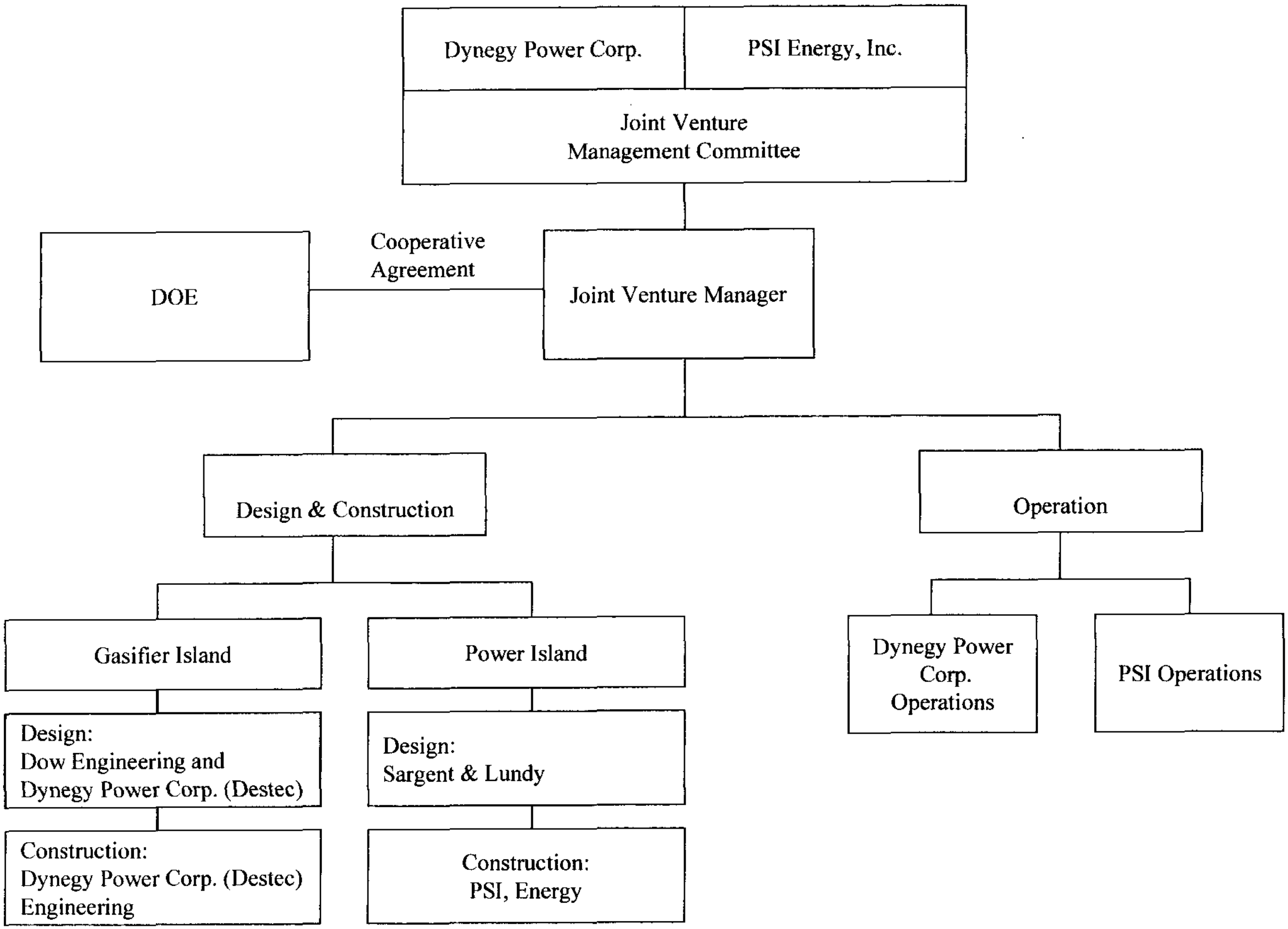


Figure 8 Project Organization

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan Original Baseline	Nov. 1993 Proj. Eval. Plan Revised Baseline	June 2, 1995 Contin. Appl'n Revised Baseline	May 1996 Proj. Mgmt. Plan Current Baseline	Completion Date
1.1.04	Signing of Gasification Services Agreement	06/24/92	06/24/92	06/24/92	06/24/92	06/24/92
1.1.05	Completion of Funding	03/15/92	11/19/92	11/19/92	11/19/92	11/19/92
1.1.06	Receipt of Air Permits	03/01/93	05/28/93	05/27/93	05/27/93	05/27/93
	Receipt of NPDES Permit Modifications	12/01/92	12/01/92	12/06/93	12/06/93	12/06/93
1.1.07	NEPA Completion	10/01/92	05/28/93	05/28/93	05/28/93	05/28/93
1.1.08	Receipt of IURC Certificate of Need	03/01/93	05/26/93	05/26/93	05/26/93	05/26/93
1.1.10	Project Management					
	Project Management Plan	10/31/92	12/04/92	12/04/92	12/04/92	12/04/92
	Financing Plan & Licensing Agreements	02/28/93	04/30/93	04/30/93	04/30/93	04/30/93
	Project Definition & Preliminary Plant Design	02/28/93	03/15/93	03/15/93	03/15/93	03/15/93
	Continuation Application	02/28/93	05/05/93	05/28/93	05/28/93	05/28/93
	Formal Project Review	03/15/93	03/30/93	03/30/93	03/30/93	03/30/93
	Draft Environmental Monitoring Plan	04/30/93	03/31/93	03/31/93	03/31/93	03/31/93
1.1.13	DOE Award	07/27/92	07/27/92	07/27/92	07/27/92	07/27/92
1.1.30	Award of EPC Subcontract for Oxygen Plant	11/15/92	12/15/92	12/15/92	12/15/92	12/15/92
1.2.01	Project Management					
	Environmental Monitoring Plan	06/30/93	06/30/93	07/28/93	07/28/93	07/28/93
	40% Completion Formal Project Review	06/30/94	06/30/94	04/05/94	04/05/94	04/05/94
	90% Completion Formal Project Review	04/30/95	04/30/95	03/09/95	03/09/95	03/09/95
	Final Public Design Report	07/31/95	01/31/95	07/01/95	07/01/95	07/07/95
	Test Plan	05/25/95	05/25/95	07/01/95	07/01/95	07/08/95
	Plant Startup Plan	07/31/95	07/31/95	05/25/95	05/25/95	05/25/95

Figure 9

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

LIST OF PROJECT MILESTONES

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan Original Baseline	Nov. 1993 Proj. Eval. Plan Revised Baseline	June 2, 1995 Contin. Appl'n Revised Baseline	May 1996 Proj. Mgmt. Plan Current Baseline	Completion Date
	Continuation Application	07/31/95	01/31/95	06/02/95	06/02/95	06/02/95
1.2.04	Start of On-Site Dirtwork	12/01/92	06/01/93	06/01/93	06/01/93	06/01/93
	Release of Gasification Plant Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.05	Mobilization to Site	09/01/93	09/10/93	09/17/93	09/17/93	09/17/93
1.2.20	Award of High Temperature Heat Recovery Unit	11/01/92	11/03/92	11/03/92	11/03/92	11/03/92
	Award of Gasifier Vessels	01/10/93	01/21/93	01/21/93	01/21/93	01/21/93
	Jobsite Reciept of HTHRU	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Jobsite Reciept of Gasifier	07/01/94	07/01/94	05/15/94	05/15/94	05/15/94
1.2.22	Start of Foundation Work	09/15/93	10/08/93	10/08/93	10/08/93	10/08/93
	Setting of First Gasifier	09/01/94	09/01/94	06/08/94	06/08/94	06/08/94
	Setting of Second Gasifier	11/01/94	11/01/94	06/14/94	06/14/94	06/14/94
	Start of Refractory Installation	09/15/94	09/15/94	08/10/94	08/10/94	08/10/94
	Initial Firing with Coal	08/15/95	07/01/95	07/01/95	07/01/95	08/17/95
	Initial Delivery of Syngas	08/15/95	07/01/95	07/01/95	07/01/95	08/25/95
1.2.29	Completion of 100 Hour Test	10/01/95	08/15/95	08/15/95	11/18/95	11/18/95
1.2.30	Jobsite Receipt of Main Air Compressor	09/01/94	09/01/94	07/15/94	07/15/94	07/15/94
	Setting of Column	08/01/94	08/01/94	03/30/94	03/30/94	03/30/94
	Delivery of Oxygen	07/15/95	07/01/95	06/19/95	06/19/95	06/14/95
1.2.43	Construction Power/Water Available	09/01/93	10/06/93	10/20/93	10/20/93	10/20/93
1.2.50	Award of Coal Handling Subcontract	04/01/93	09/03/93	09/03/93	09/03/93	09/03/93
	Delivery of Coal to Syngas Facility	07/15/94	01/15/95	05/18/95	05/18/95	05/18/95
1.2.60	Award of STG Modification Subcontract	01/01/93	01/01/93	06/04/93	06/04/93	06/04/93

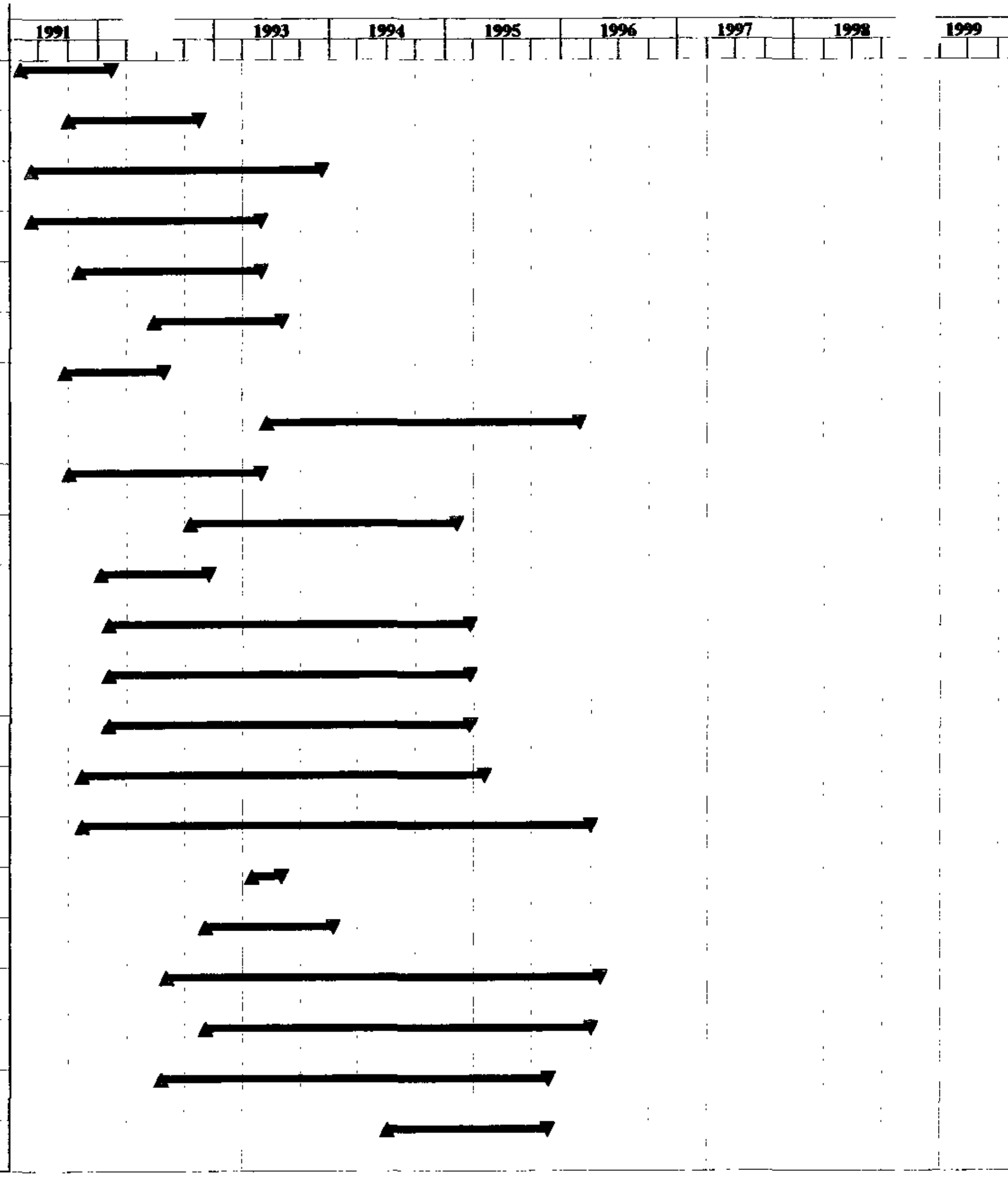
Figure 9

WABASH RIVER COAL GASIFICATION REPOWERING PROJECT

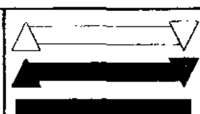
LIST OF PROJECT MILESTONES

WBS	MILESTONE	Nov. 1992 Proj. Mgmt. Plan Original Baseline	Nov. 1993 Proj. Eval. Plan Revised Baseline	June 2, 1995 Contin. Appl'n Revised Baseline	May 1996 Proj. Mgmt. Plan Current Baseline	Completion Date
1.2.70	Award of Gas Turbine Generator (GTG)	01/31/92	01/31/92	01/31/92	01/31/92	01/31/92
	Award of Heat Recovery Steam Generator (HRSG)	10/15/92	10/15/92	10/15/92	10/15/92	10/15/92
	Jobsite Delivery of GTG	03/01/94	01/01/94	03/18/94	03/18/94	03/18/94
1.2.75	Hydrotest of HRSG	04/15/95	04/15/95	03/31/95	03/31/95	03/31/95
	Synchronization of GTG	05/15/95	01/15/95	06/07/95	06/07/95	06/10/95
1.2.81	GTG Operation on Oil	01/01/95	01/01/95	06/07/95	06/07/95	06/09/95
	GTG Operation on Syngas	05/15/95	08/15/95	08/15/95	10/03/95	10/03/95
1.3.01	Project Management					
	Startup and Modification Report	12/01/95	12/01/95	11/01/95	01/01/99	
	Project Management Plan Update		not represented	11/01/95	05/01/96	05/16/96
	Formal Project Reviews	Annual				
	Draft Final Technical Report	07/31/98	07/31/98	09/30/98	01/01/99	
	Technology Performance & Economic Evaluation	11/30/98	11/30/98	10/01/98	02/01/99	
	Final Technical Report	12/31/98	12/31/98	11/30/98	02/28/99	

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
1010	OVERALL PROJECT - SCOPE DEFINITION	100	01MAY91A	14FEB92A
1050	FINANCE/FUNDING	100	01OCT91A	15NOV92A
1060	PERMIT PREPARATION & SUBMITTAL	100	07JUN91A	06DEC93A
1070	NEPA PROCESS	100	07JUN91A	28MAY93A
1080	IURC APPROVAL	100	01NOV91A	26MAY93A
1100	PROJECT MANAGEMENT/ENVIRONMENTAL PLANS	100	19JUN92A	30JUL93A
1130	DOE COOPERATIVE AGREEMENT	100	16SEP91A	27JUL92A
1140	PROCESS CONSULTANTS & FEES	100	15JUN93A	29FEB96A
1200	GASIFICATION PLANT PROCESS DESIGN	100	01OCT91A	30MAY93A
1220	GASIFICATION PLANT AREA DESIGN	100	15OCT92A	01FEB95A
1300	OXYGEN PLANT PACKAGE DESIGN	100	10JAN92A	15DEC92A
1400	UTILITIES DESIGN	100	02FEB92A	15MAR95A
1500	COAL HANDLING DESIGN	100	01FEB92A	15MAR95A
1600	REPOWERING DESIGN	100	01FEB92A	15MAR95A
1700	GAS TURBINE AREA DESIGN	100	12NOV91A	01MAY95A
1900	POWER GENERATION PROJECT MGMT/COMMON ENGS	100	12NOV91A	01APR96A
2010	PROJECT MANAGEMENT PLAN	100	01MAY93A	30JUL93A
2040	SITE PREPARATION	100	01DEC92A	14JAN94A
2050	GASIFICATION PLANT CONST MANAGEMENT	100	01AUG92A	01MAY96A
2060	GAS TURBINE AREA CONSTRUCTION MANAGEMENT	100	01DEC92A	01APR96A
2150	GP PRE-OPERATIONS MANAGEMENT	100	12JUL92A	18NOV95A
2160	GT SELECTION & TRAINING PLANT OPERATORS	100	30JUN94A	18NOV95A



Start Date	01JUN91
Finish Date	30DEC99
Data Date	31DEC99
Run Date	05JUN00 13:32



6216 Sheet 1 of 2

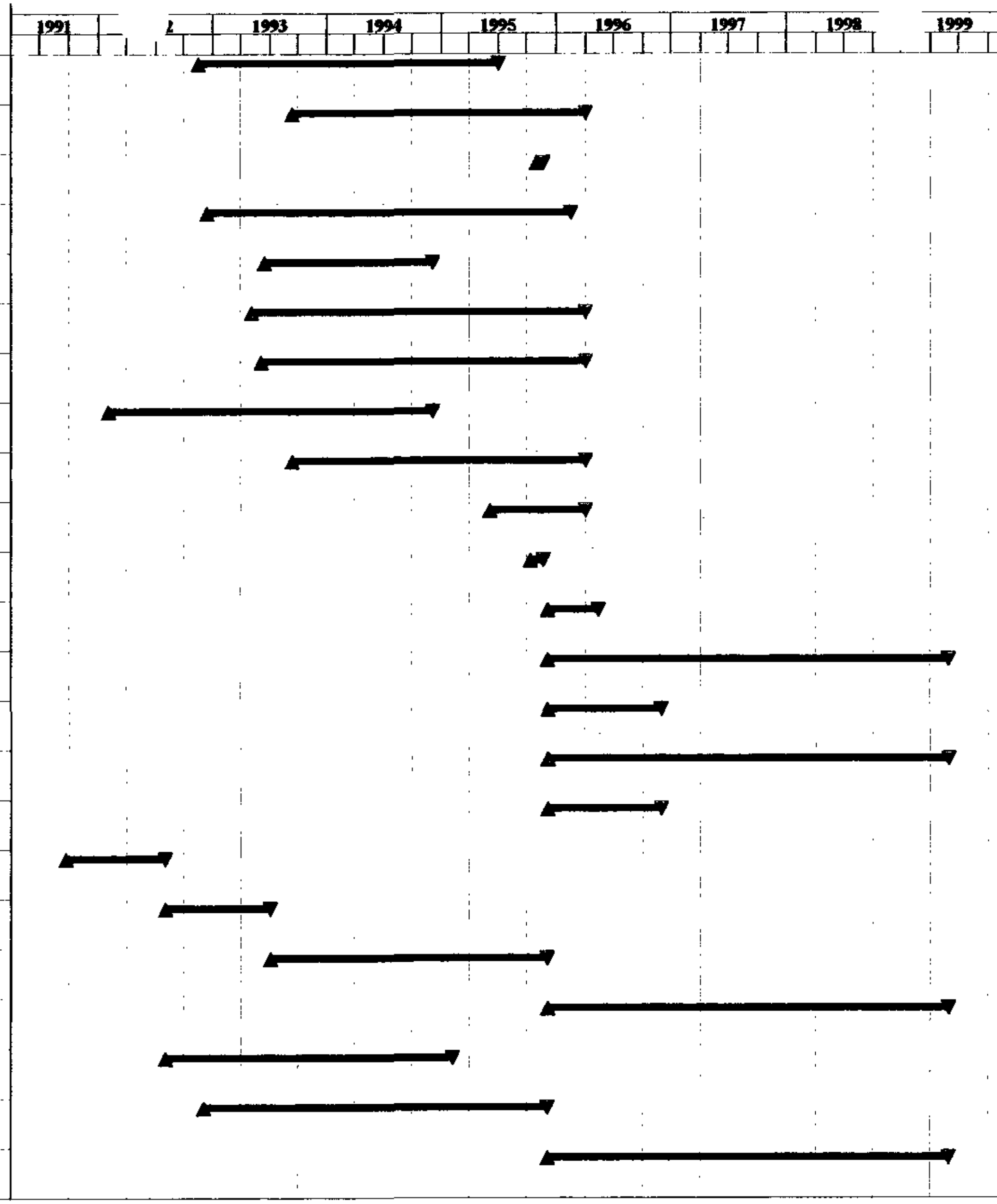
DESTEC ENGINEERING, INC.

VABASH RIVER COAL GASIF REPOWER PRO

DOE PROJECT PLAN

Figure 10

Activity ID	Activity Description	% Comp.	Early Start	Early Finish
2200	GASIFICATION PLANT EQUIPMENT PROCUREMENT	100	15NOV92A	30JUN95A
2220	GASIFICATION PLANT CONSTRUCTION	100	13SEP93A	01APR96A
2290	GAS PLANT ACCEPTANCE TESTING	100	25OCT95A	18NOV95A
2300	OXYGEN PLANT PROCUREMENT & CONSTRUCTION	100	15DEC92A	17FEB96A
2430	UTILITIES CONSTRUCTION	100	14JUN93A	01DEC94A
2500	COAL HANDLING PROCUREMENT & CONSTRUCTION	100	03MAY93A	01APR96A
2600	REPOWERING PROCUREMENT & CONSTRUCTION	100	04JUN93A	01APR96A
2700	GT AREA EQUIPMENT PROCUREMENT	100	31JAN92A	30NOV94A
2750	GAS TURBINE AREA CONSTRUCTION	100	13SEP93A	01APR96A
2810	GAS TURBINE ACCEPTANCE TESTING	100	01JUN95A	01APR96A
2990	PLANT PERFORMANCE TESTING	100	11OCT95A	18NOV95A
3010	PROJECT MANAGEMENT PLAN UPDATE	100	01DEC95A	16MAY96A
3060	ENVIRONMENTAL REPORTING	100	01DEC95A	01JUN99A
3130	WARRANTY ADMINISTRATION	100	01DEC95A	02DEC96A
3140	GP COMMERCIAL OPERATION - DEMONSTRATION PERIOD	100	01DEC95A	01JUN99A
3240	GT COMMERCIAL OPERATION - DEMONSTRATION PERIOD	100	01DEC95A	02DEC96A
11301PD	PRE AWARD PERIOD	100	16SEP91A	01AUG92A
11311BP	1ST BUDGET PERIOD	100	01AUG92A	30JUN93A
20402BD	2ND BUDGET PERIOD	100	30JUN93A	30NOV95A
30403BD	3RD BUDGET PERIOD	100	01DEC95A	01JUN99A
11312PD	PHASE I DESIGN	100	01AUG92A	01FEB95A
20403PD	PHASE II CONSTRUCTION	100	01DEC92A	30NOV95A
30514PD	PHASE III OPERATION	100	01DEC95A	01JUN99A



PLANT OPERATION STATISTICS
1999

GASIFICATION PLANT

PERFORMANCE DATA

Coal Gas Efficiency	74.0%
Gasifier on Coal (Hours)	3,496
Gasification Plant Capacity Factor (Produced)	37.3 %
Gasification Plant Capacity Factor (Delivered)	35.7 %

PRODUCTION DATA

Syngas on Spec (MMBtu)	5,813,151
1600# Steam (Mlbs)	1,480,908
Sulfur (Mlbs)	17,113
Slag, Moisture Free (Mlbs)	45,216

DELIVERED PRODUCTION

Actual Syngas Delivered (MMBtu)	5,560,483
1600# Steam (Mlbs)	1,431,236

MATERIAL/ENERGY USED

Coal, Moisture Free (Tons)	315,951
Coal (MMBtu)	7,772,568
Intermediate Pressure Steam (Mlbs)	103,390
Electrical Power, Total (MWh)	211,369
Oxygen, (Tons)	289,935
Fuel Gas (Mlbs)	6473

POWER PLANT

PERFORMANCE DATA

Combustion Turbine Operating Hours (Syngas)	3,421
Combustion Turbine Operating Hours (Total)	4,196
Steam Turbine Operating Hours	4,063

PRODUCTION DATA

Combustion Turbine Generator (MWH)	681,210
Steam Turbine Generator (MWH)	322,643

Figure 11

APPENDIX C

List of Technical and Trade Publications Concerning WRCGRP

Appendix C
LISTING OF TECHNICAL PUBLICATIONS
(PUBLIC INFORMATION)

DATE	TITLE/SOURCE	AUTHOR(S)
April 22, 1999	EPRI Gasification Users Conference "Current Experience at the Wabash River Coal Gasification Repowering Project" West Terre Haute, Indiana	Lynch
June 7, 1999	ASME Turbo Expo '99 "Current Experience at the Wabash River Coal Gasification Repowering Project" Indianapolis, Indiana	Amick
June 21-24, 1999	Seventh Clean Coal Technology Conference "Wabash River in its Fourth Year of Commercial Operation" Knoxville, Tennessee	Douglas
October 11, 1999	DOE Sixteenth Annual International Pittsburg Coal Conference "Alternate Fuel Testing at the Wabash River Coal Gasification Repowering Project" Pittsburg, Pennsylvania	Tsang
October 18-20, 1999	1999 Gasification Technologies Conference "Wabash River in its Fourth Year of Commercial Operation" San Francisco, California	Keeler
October 18-20, 1999	1999 Gasification Technologies Conference "Improved Performance of the Destec Gasifier" San Francisco, California	Breton
October 20-22, 1999	Wye Institute Strategic Initiative for Coal and Power "Wabash River" Wye River Institute, Maryland	Amick

APPENDIX D

Run Documentation and Production Graphs

Appendix D
Run Documentation and Production Graphs

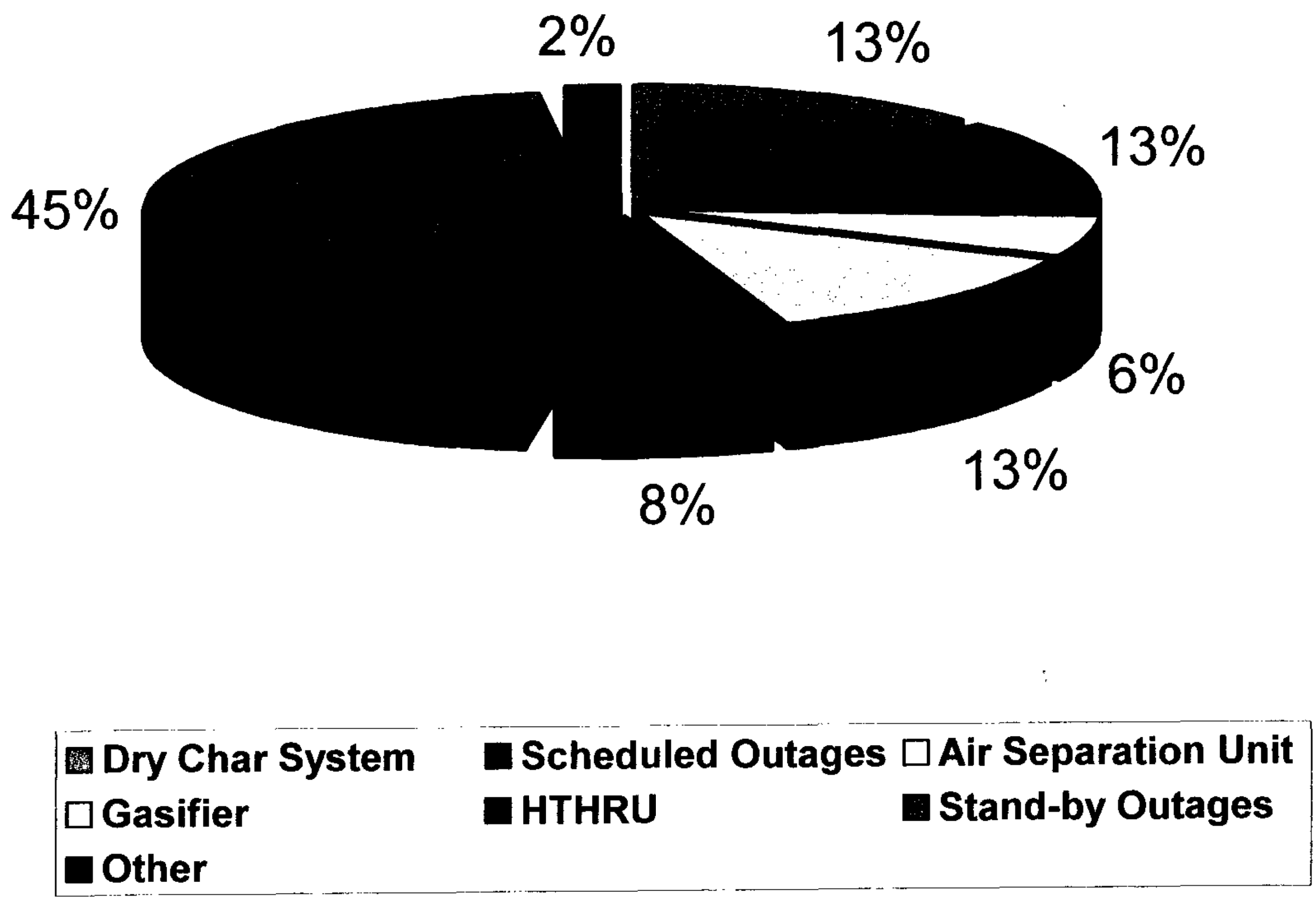
Run Documentation
1999 Downtime Analysis
Operational Run Periods for 1999
Monthly Plant Performance Data
1999 Cold Gas Efficiency
1999 Hours of Operation
1999 Gasifier Hours on Coal
1999 Produced Syngas
1999 1600# Steam Produced
1999 Sulfur Produced
1999 Slag Production
1999 Delivered Syngas
1999 Delivered #1600 LB Steam
1999 Feed to Gasifier
1999 Monthly Power Production
1999 Energy Utilization (Gasifier)
1999 Electrical Energy Utilization
1999 Coal Feed to Gasifier
1999 Total Sulfur Emissions
1999 Pounds of SO2/MMBtu of Coal Feed

1999 Run Documentation

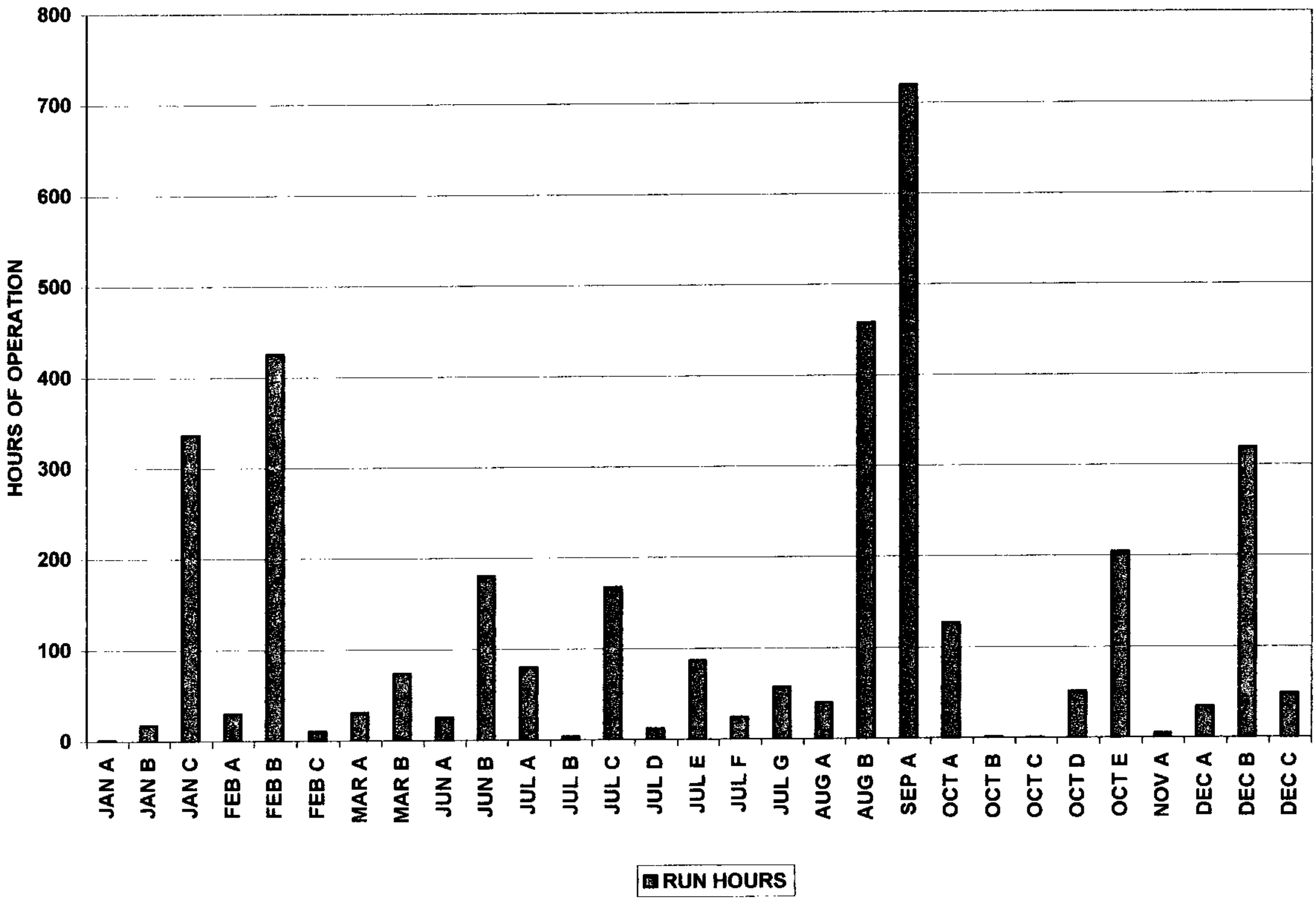
RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
JAN99A	01/07/99 01:58	01/07/99 03:23	1.42	Transferred off coal operation due to Slag Grinder problems.
JAN99B	01/07/99 14:44	01/08/99 08:15	17.52	Transferred off coal operation due to a syngas leak in one of the Low Temperature Heat Exchangers.
JAN99C	01/10/99 15:34	01/24/99 15:53	336.32	Transferred off coal operation due to a plugged taphole.
FEB99A	02/06/99 12:13	02/07/99 18:00	29.78	Gasifier tripped on high Oxygen to Coal ratio due to a piston failure on the main slurry pump.
FEB99B	02/07/99 23:01	02/25/99 16:18	425.28	Transferred off coal operation due to high differential pressure across the sour water carbon filters.
FEB99C	02/28/99 12:06	02/28/99 22:15	10.15	Transferred off coal operation due to failed ceramic test filter in the primary dry char system.
MAR99A	03/12/99 10:19	03/13/99 17:22	31.05	Transferred off coal operation due to failed combustion turbine.
JUN99A	6/22/99 02:23	6/23/99 3:05	24.70	Gasifier tripped on Hi Oxygen to fuel ratio due to loss of slurry flow from a plugged pump suction line.
JUN99B	6/23/99 11:08	7/1/99 00:00	180.87	Continuing
JUL99A	7/1/99 00:00	7/4/99 07:41	79.68	Transferred off coal operation due to a turbine trip caused by a blown fuse.
JUL99B	7/5/99 03:35	7/5/99 07:06	3.53	Transferred off coal operation due to problems with the turbine's syngas stop ratio valves not operating.
JUL99C	7/5/99 11:38	7/12/99 10:59	167.35	Gasifier tripped on high O2:coal ratio when the slurry feed pump lost suction flow.
JUL99D	7/12/99 13:58	7/13/99 01:48	11.83	Transferred off coal operation due to high sulfur emissions resulting from a faulty air demand analyzer reading in the sulfur recovery unit.
JUL99E	7/13/99 08:19	7/16/99 23:17	86.97	Transferred off coal operation due to a valve problem associated with the absorber bed in the ASU.
JUL99F	7/17/99 13:53	7/18/99 14:09	24.27	Transferred off coal operation due to a turbine trip caused by faulty I/O cards in their control system.
JUL99G	7/19/99 14:09	7/21/99 22:59	56.83	Transferred off coal operation due to a tube leak in the HRSG.

RUN	START	FINISH	DURATION (Hours)	REASON FOR TERMINATION
AUG99A	8/8/99 16:49	8/10/99 8:13	39.40	Transferred off coal operation due to a slag grinder seal leak.
AUG99B	8/12/99 22:17	9/1/99 00:00	457.72	Continuing
SEP99A	9/1/99 00:00	10/1/99 00:00	720.00	Continuing
OCT99A	10/1/99 00:00	10/6/99 07:10	127.17	Transferred off coal operation due to a failed slurry mixer.
OCT99B	10/9/99 08:07	10/9/99 9:19	1.20	Transferred off coal operation to repair a failed slurry valve.
OCT99C	10/10/99 22:32	10/10/99 23:06	0.57	Transferred off coal operation to repair a leak on a slurry flow meter.
OCT99D	10/11/99 12:49	10/13/99 16:04	51.25	Transferred off coal operation to replace failed slurry valves.
OCT99E	10/14/99 10:12	10/22/99 22:29	204.28	Transferred off coal operation for scheduled fall outage.
NOV99A	11/21/99 20:09	11/22/99 00:56	4.78	Transferred off coal operation due to a syngas leak from the dry char return line.
DEC99A	12/12/99 23:51	12/14/99 10:03	34.20	Reactor tripped on high oxygen:coal ratio due to loss of slurry flow from plugged pump suction.
DEC99B	12/14/99 15:08	12/27/99 22:00	318.87	Transferred off coal operation to repair packing leak on slag crusher.
DEC99C	12/29/99 23:08	01/01/00 00:00	48.97	Continuing

1999 Downtime Analysis



OPERATIONAL RUN PERIODS FOR 1999



1999 RUN CAMPAIGNS

Monthly Plant Performance Data

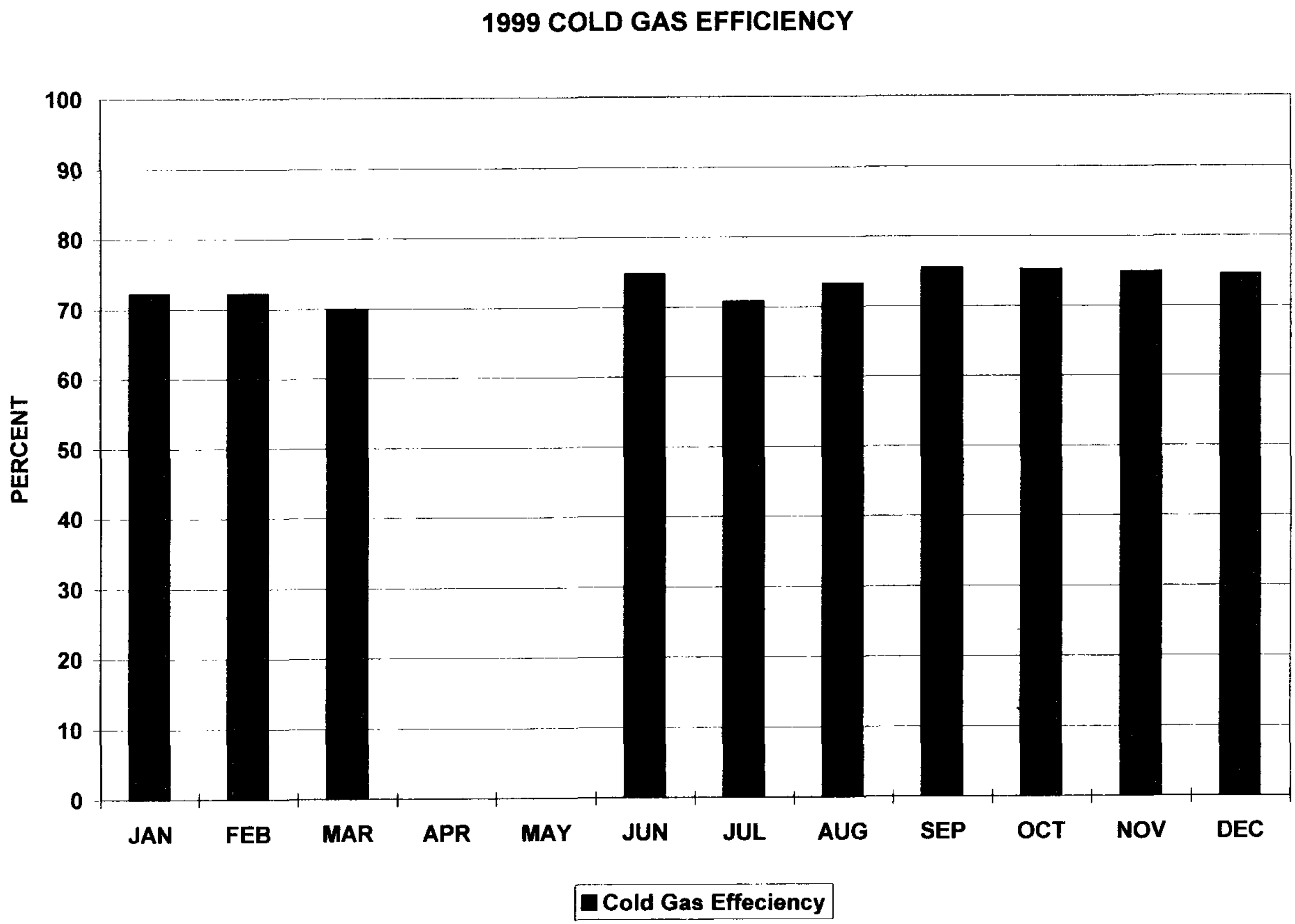
	JAN	FEB	MAR	APR	MAY
PERFORMANCE DATA					
Coal Gas Efficiency	72.14	72.12	69.87	0	0
Gasifier on Coal (Hours)	354.47	465.25	31.08	0	0
PRODUCTION DATA					
Syngas on Spec (MMBtu)	599864.4	797006	45731.8	0	0
1600# Steam (Mlbs)	145994.7	189305.7	12613.8	0	0
Sulfur (Mlbs)	1607.1	2480	104.4	0	0
Slag, Moisture Free (Tons)	4607.6	6207.7	364.8	0	0
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	571432.8	779106.5	39409.3	0	0
1600# Steam (Mlbs)	142711.8	187820.8	11146.8	0	0
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	32196.4	43375.1	2550	0	0
Coal (MMBtu)	792048.9	1067051	62730.9	0	0
Intermediate Pressure Steam (Mlbs)	13561.6	14162.1	5900.1	1836.7	1135.4
Electrical Power, Total (MWh)	23650.2	22213.1	17625.9	955.2	842.9
Oxygen, (Tons)	29480	39526.9	2587.5	0	0
Fuel Gas (Mlbs)	1043.6	826.4	601.8	0	0
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	113.15	128.39	115.45	0	0
Total SO2 Emissions (lbs)	66468	92642.2	8622	0	0
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.084	0.087	0.137	0	0
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	70524	91395	5624	0	0
Steam Turbine Generator (MWh)	33794	43734	2770	0	0
Total Gross Generation (MWh)	104318	135129	8394	0	0
Total Syngas Generation (MWh)	94300	129048	6466	0	0

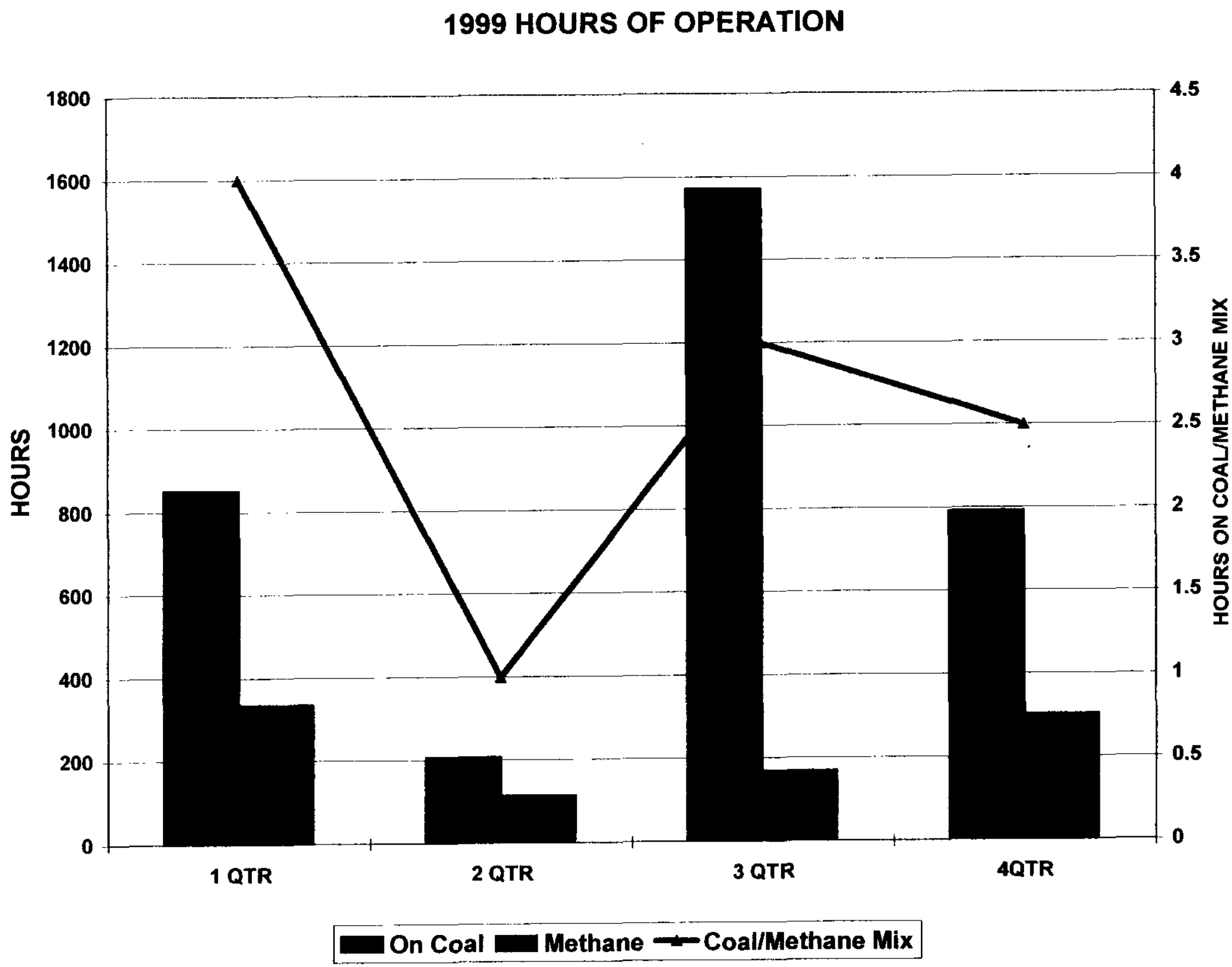
Monthly Plant Performance Data

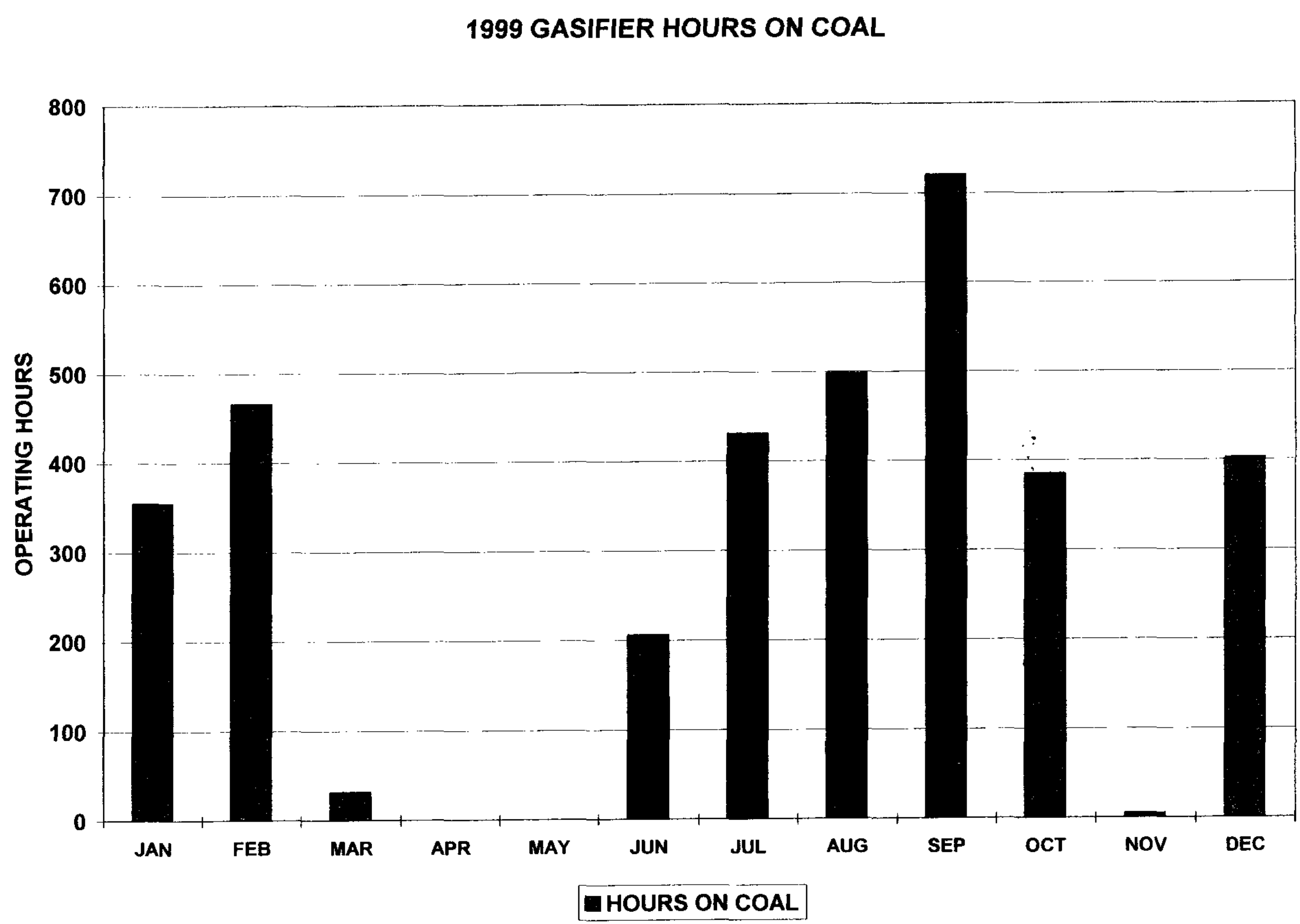
	JUN	JUL	AUG	SEP	OCT
PERFORMANCE DATA					
Coal Gas Efficiency	74.7	70.73	73.27	75.38	75.13
Gasifier on Coal (Hours)	205.56	430.54	497.21	720	384.65
PRODUCTION DATA					
Syngas on Spec (MMBtu)	333038.7	682051.5	825483	1204573	637765.9
1600# Steam (Mlbs)	93412	188199	213421.9	296513.2	156113.6
Sulfur (Mlbs)	962.5	1845.2	2532.2	3874.5	1791.8
Slag, Moisture Free (Tons)	2570.6	5499.5	6494.1	9292	4894.5
DELIVERED PRODUCTION					
Actual Syngas Delivered (MMBtu)	322896.3	643640.1	794627.9	1152059	602460.8
1600# Steam (Mlbs)	86876.4	175828.4	204156.5	287675	151059.6
MATERIAL/ENERGY USED					
Coal, Moisture Free (Tons)	17962.4	38429.3	45377.6	64924	34203.4
Coal (MMBtu)	441883.8	945381.9	1116314	1597164	841422.5
Intermediate Pressure Steam (Mlbs)	6724.7	10784.4	11625.1	11436.3	9867.4
Electrical Power, Total (MWh)	19124.9	19862.9	24092.9	25820.5	20767.3
Oxygen, (Tons)	16741.7	35135.2	41265.9	59282	31766.2
Fuel Gas (Mlbs)	662.4	856.4	553.1	80.6	702.9
PLANT EMISSION DATA					
Average Total Sulfur in Syngas (ppm)	118.47	116.18	109.03	119.91	103.51
Total SO2 Emissions (lbs)	38711.5	83914.7	88588.8	129019.6	68813.1
SO2, (Total Plant lbs/MMBtu of Coal Feed)	0.88	0.089	0.084	0.81	0.082
POWER PLANT PRODUCTION DATA					
Combustion Turbine Generator (MWh)	36586	92524	102116	132522	71184
Steam Turbine Generator (MWh)	19443	43282	47047	62623	31702
Total Gross Generation (MWh)	56029	135806	149163	195145	102886
Total Syngas Generation (MWh)	54052	112726	136610	195028	92250

Monthly Plant Performance Data

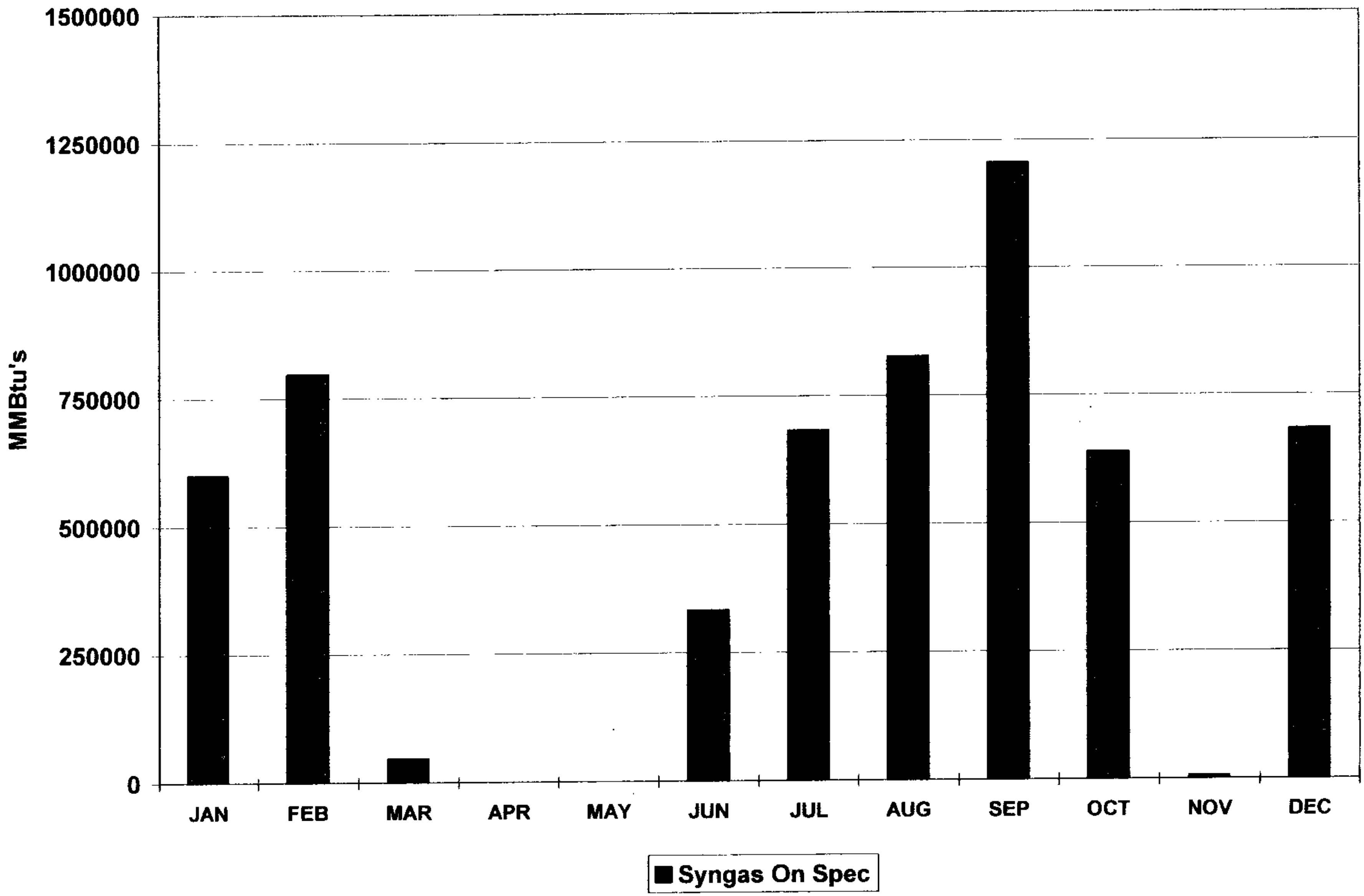
	NOV	DEC
PERFORMANCE DATA		
Coal Gas Efficiency	74.85	74.5
Gasifier on Coal (Hours)	4.79	401.96
PRODUCTION DATA		
Syngas on Spec (MMBtu)	6139.4	681497.7
1600# Steam (Mlbs)	2383.2	182950.9
Sulfur (Mlbs)	77.8	1837.2
Slag, Moisture Free (Tons)	51.7	5233.5
DELIVERED PRODUCTION		
Actual Syngas Delivered (MMBtu)	4930.6	649920.2
1600# Steam (Mlbs)	1623.6	182336.8
MATERIAL/ENERGY USED		
Coal, Moisture Free (Tons)	363.7	36569.2
Coal (MMBtu)	8947.4	899623.2
Intermediate Pressure Steam (Mlbs)	2933.8	13421.9
Electrical Power, Total (MWh)	12303.8	24109.6
Oxygen, (Tons)	6.1	34143
Fuel Gas (Mlbs)	0	1146.2
PLANT EMISSION DATA		
Average Total Sulfur in Syngas (ppm)	110.08	104.81
Total SO2 Emissions (lbs)	12460.1	70967.1
SO2, (Total Plant lbs/MMBtu of Coal Feed)	4.25	0.79
POWER PLANT PRODUCTION DATA		
Combustion Turbine Generator (MWh)	1058	77677
Steam Turbine Generator (MWh)	483	37765
Total Gross Generation (MWh)	1541	115442
Total Syngas Generation (MWh)	956	110507

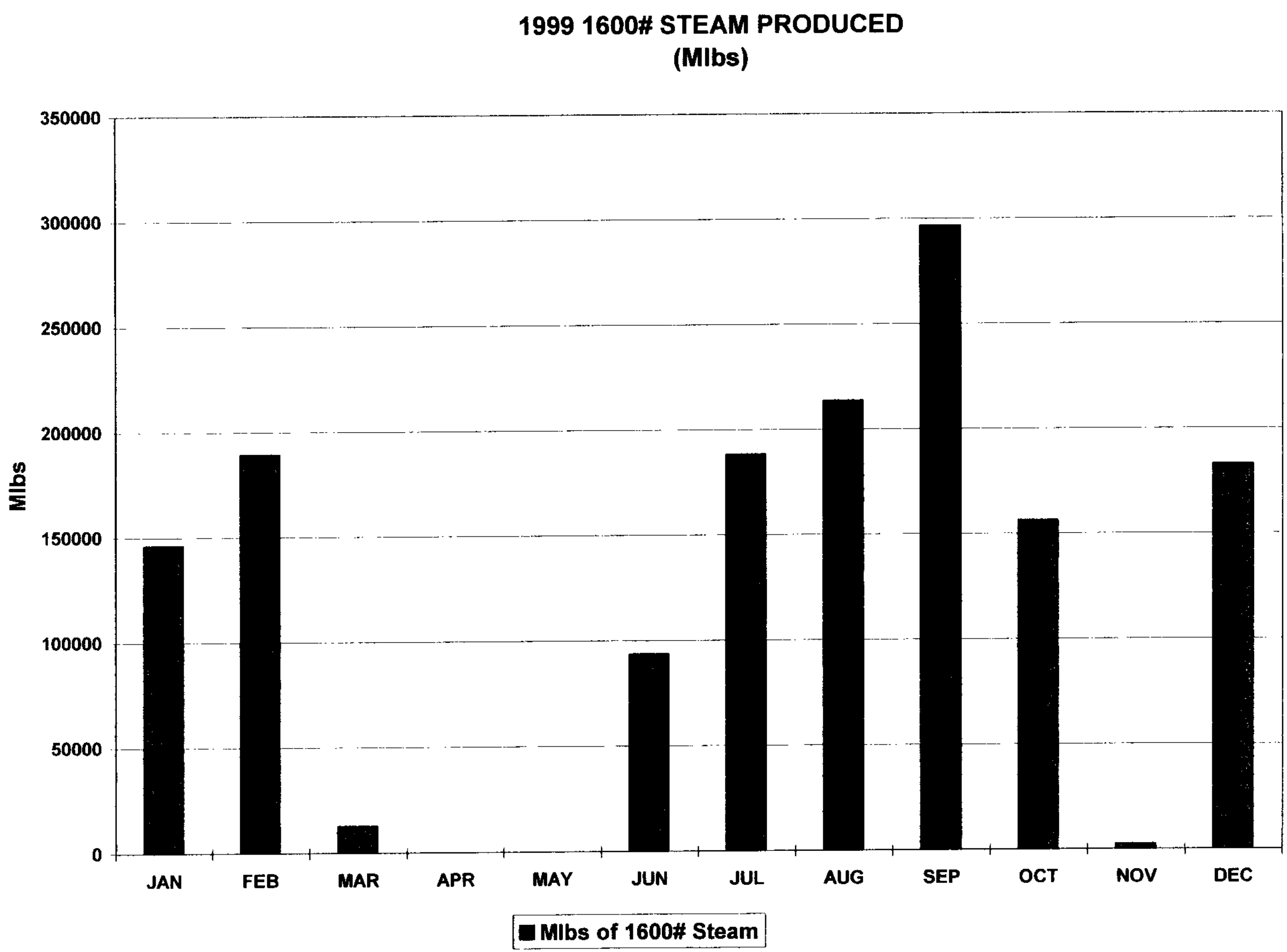

1999 COLD GAS EFFICIENCY
100
90
80
70
60
50
40
30
20
10
0
PERCENT
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Cold Gas Effeciency


1999 HOURS OF OPERATION
HOURS
1800
1600
1400
1200
1000
800
600
400
200
0
1 QTR
2 QTR
3 QTR
4QTR
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
HOURS ON COAL/METHANE MIX
On Coal
Methane
Coal/Methane Mix


1999 GASIFIER HOURS ON COAL
OPERATING HOURS
800
700
600
500
400
300
200
100
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
HOURS ON COAL

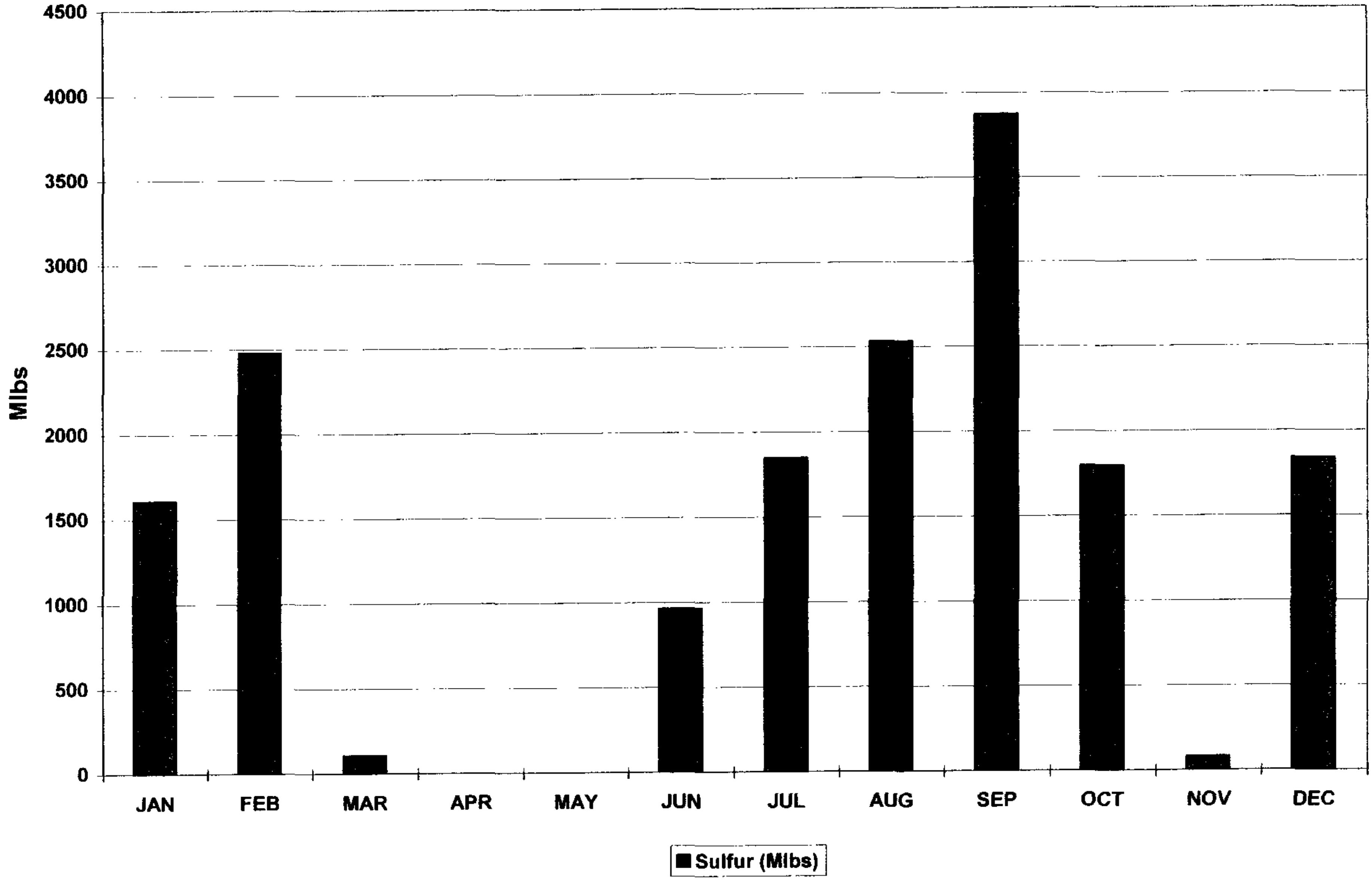
1999 PRODUCED SYNGAS (ON-SPECIFICATION)



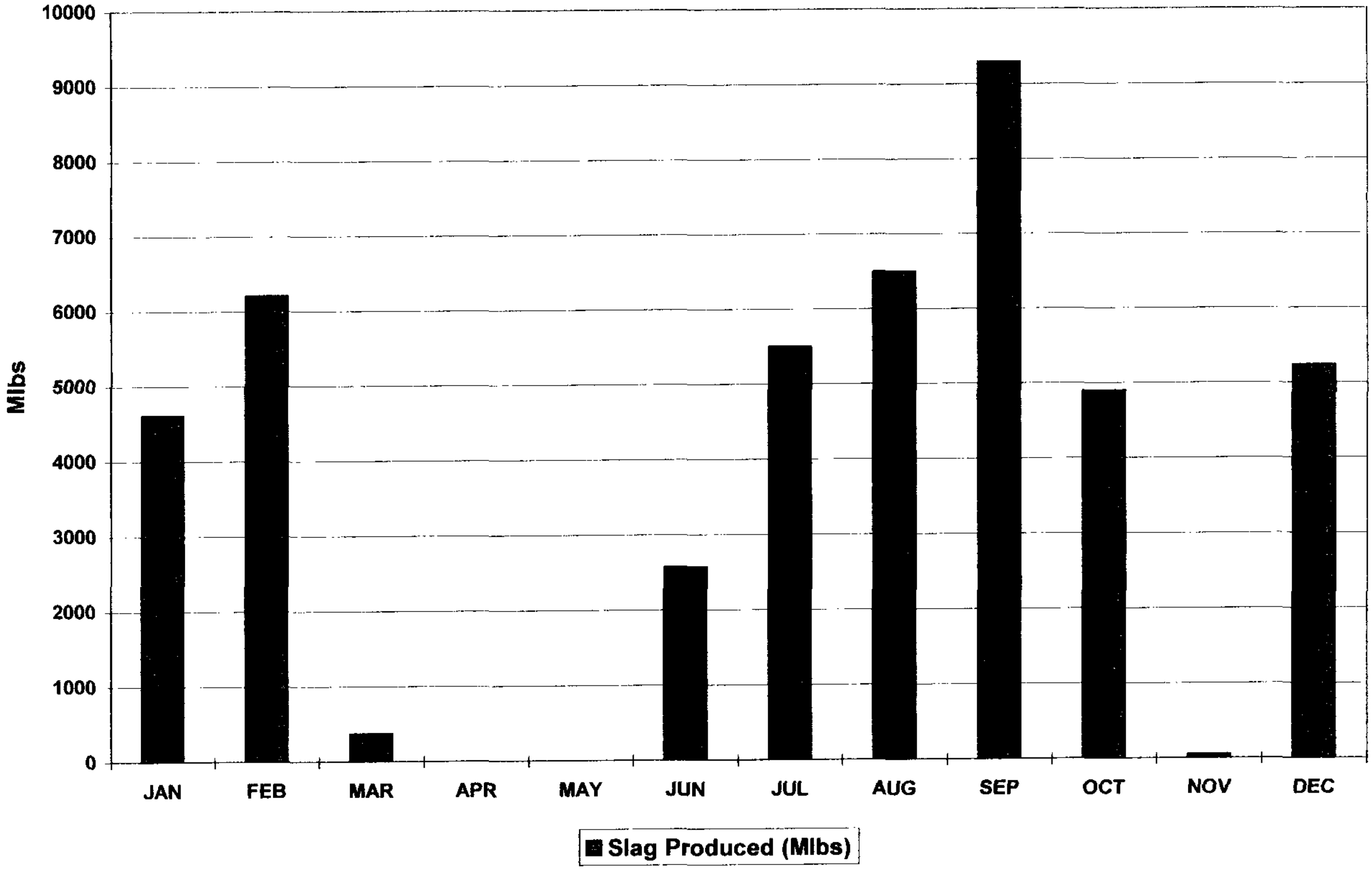


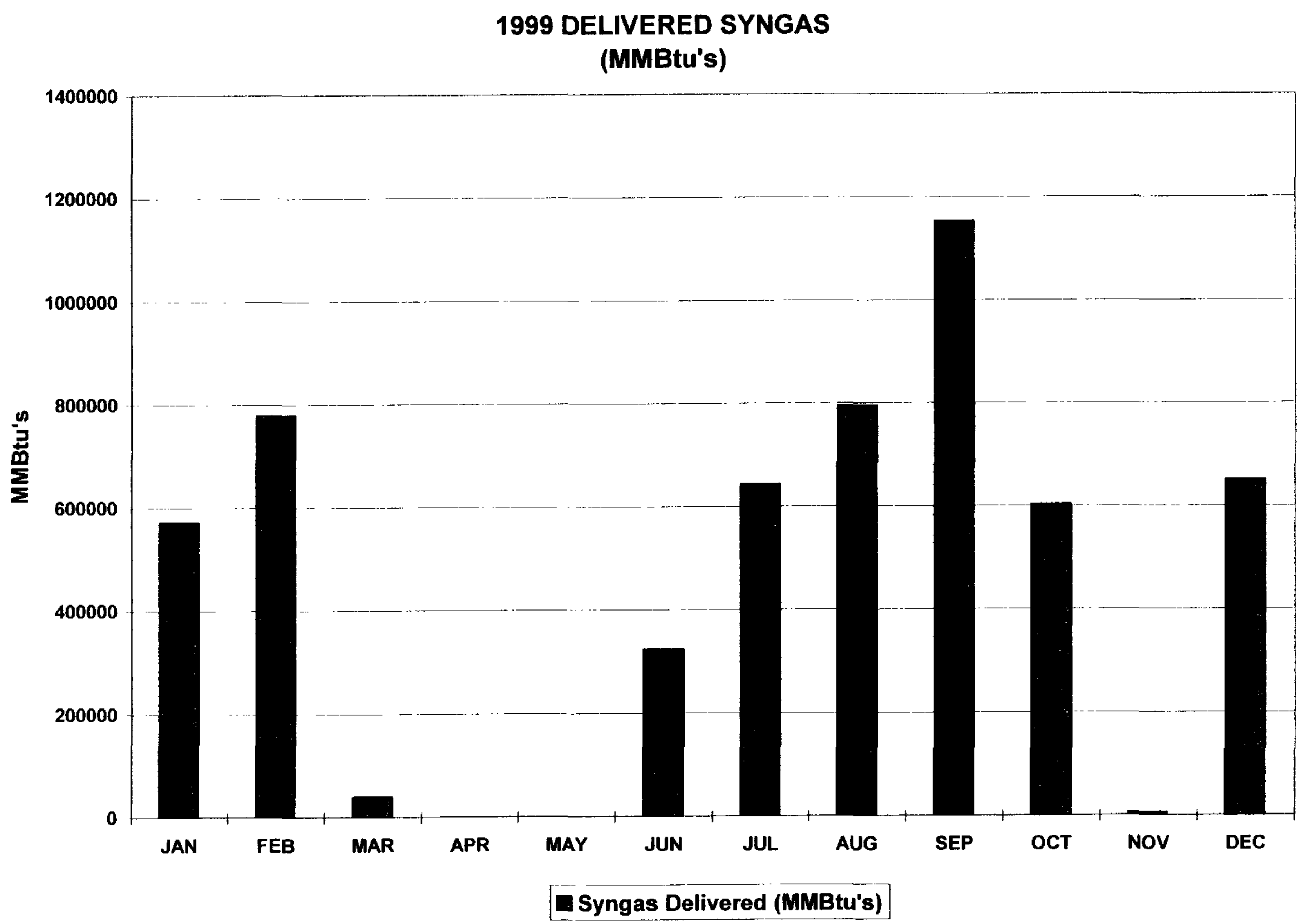
1999 1600# STEAM PRODUCED
(Mlbs)
Mlbs
350000
300000
250000
200000
150000
100000
50000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Mlbs of 1600# Steam

1999 SULFUR PRODUCED
(Mlbs)

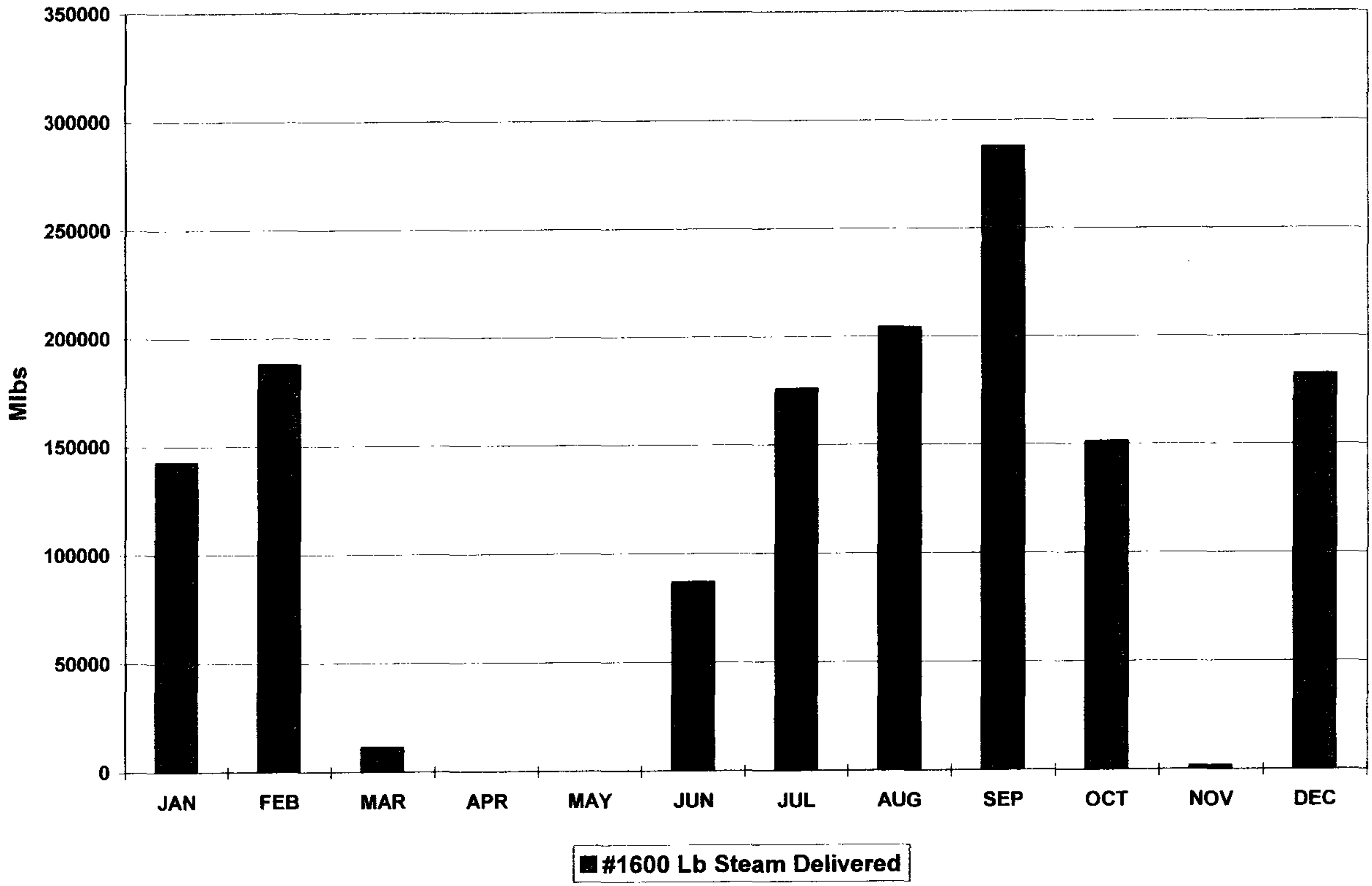


1999 SLAG PRODUCTION
(Mlbs - Moisture Free)

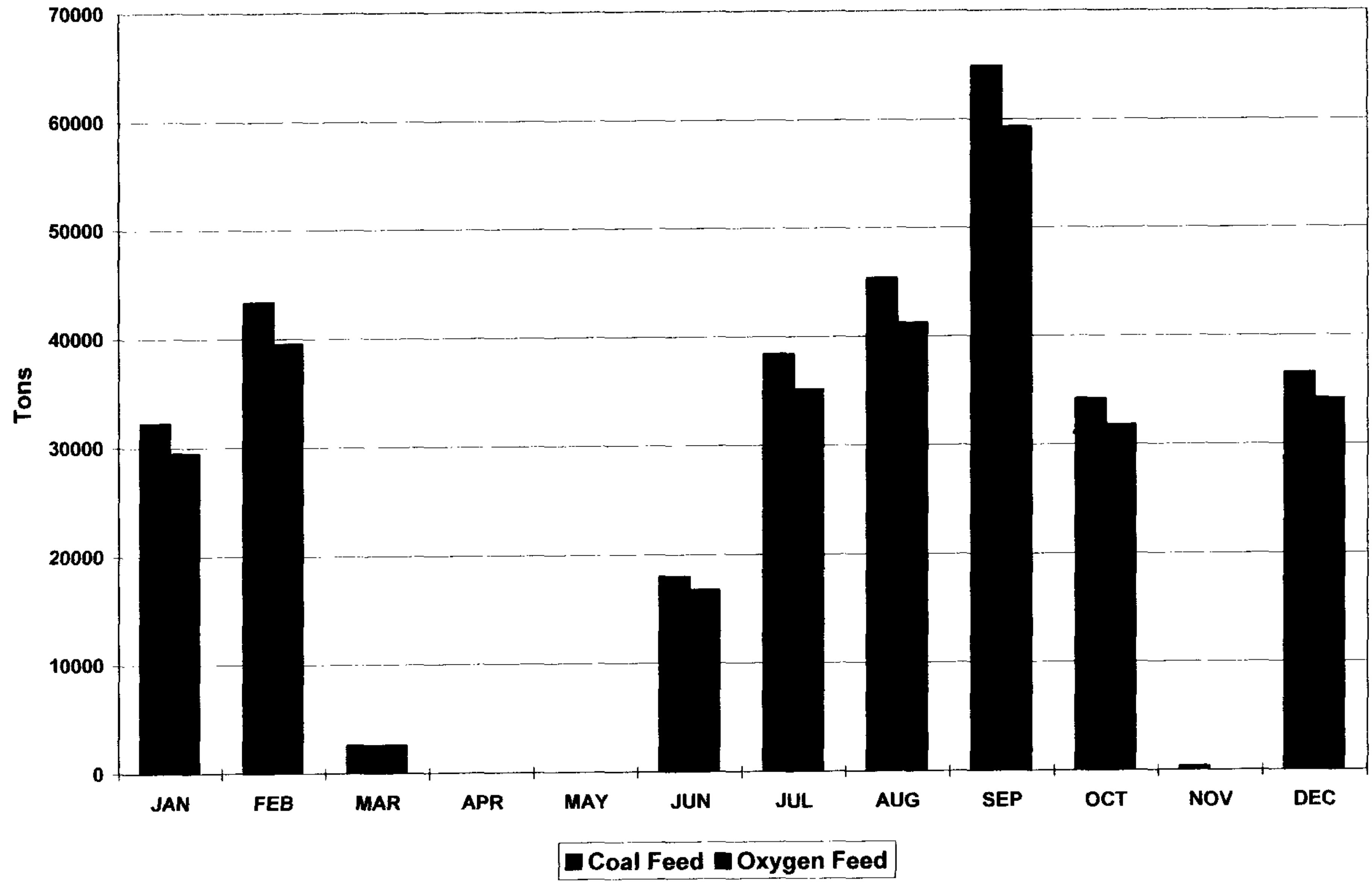



1999 DELIVERED SYNGAS
(MMBtu's)
MMBtu's
1400000
1200000
1000000
800000
600000
400000
200000
0
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEP
OCT
NOV
DEC
Syngas Delivered (MMBtu's)

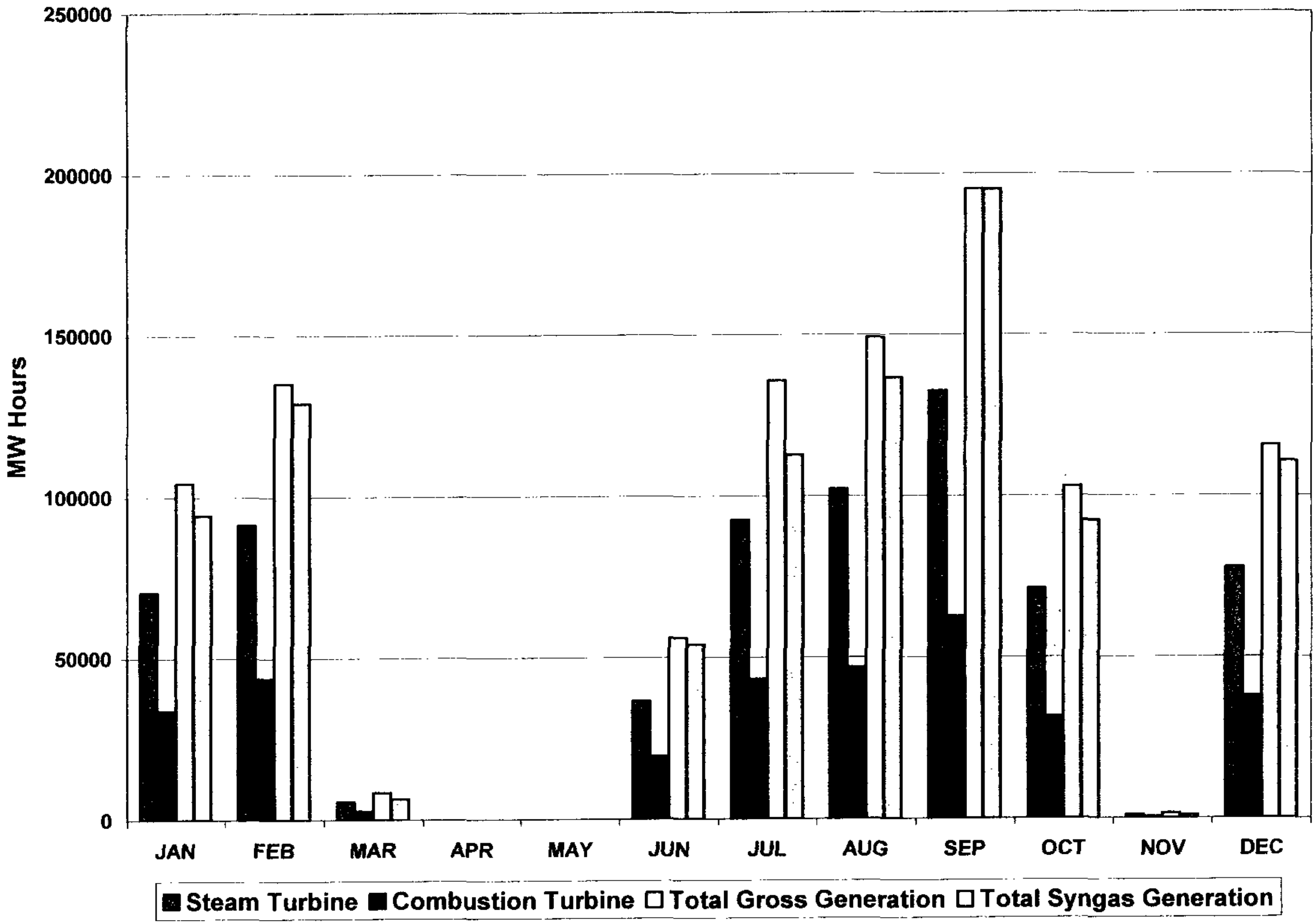
1999 DELIVERED #1600 LB STEAM
(Mlbs)



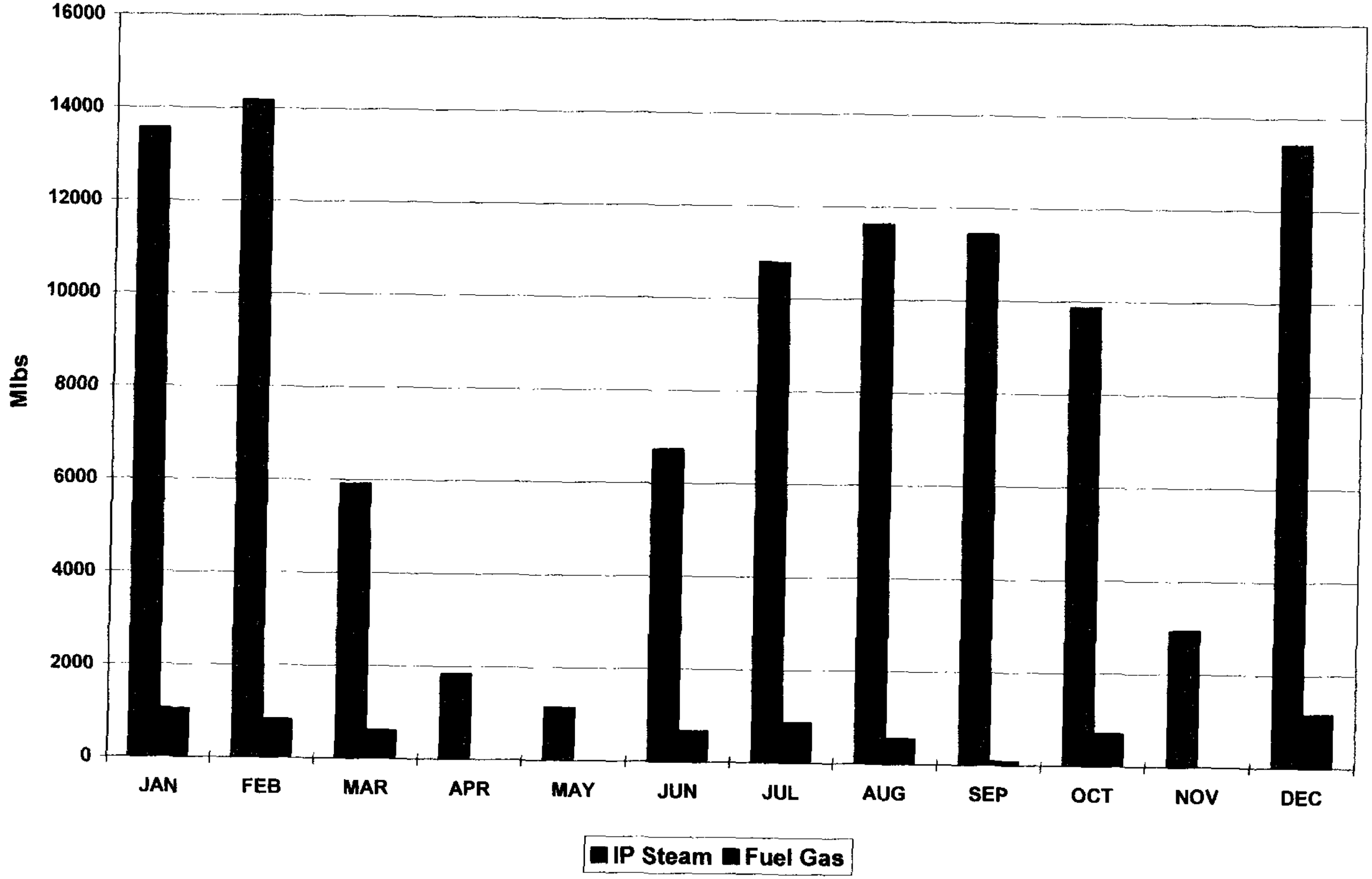
1999 FEED TO GASIFIER (TONS)



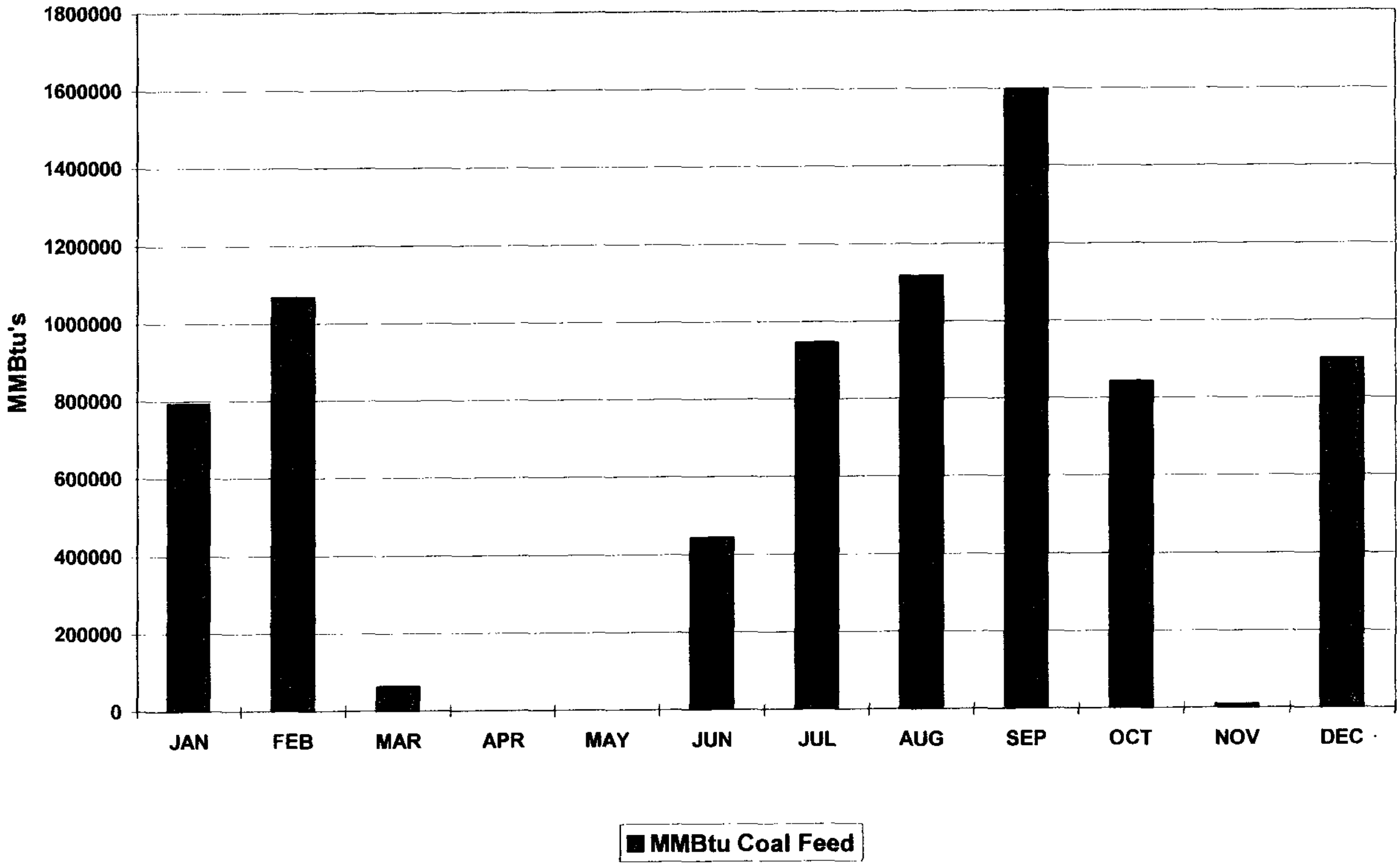
1999 Monthly Power Production



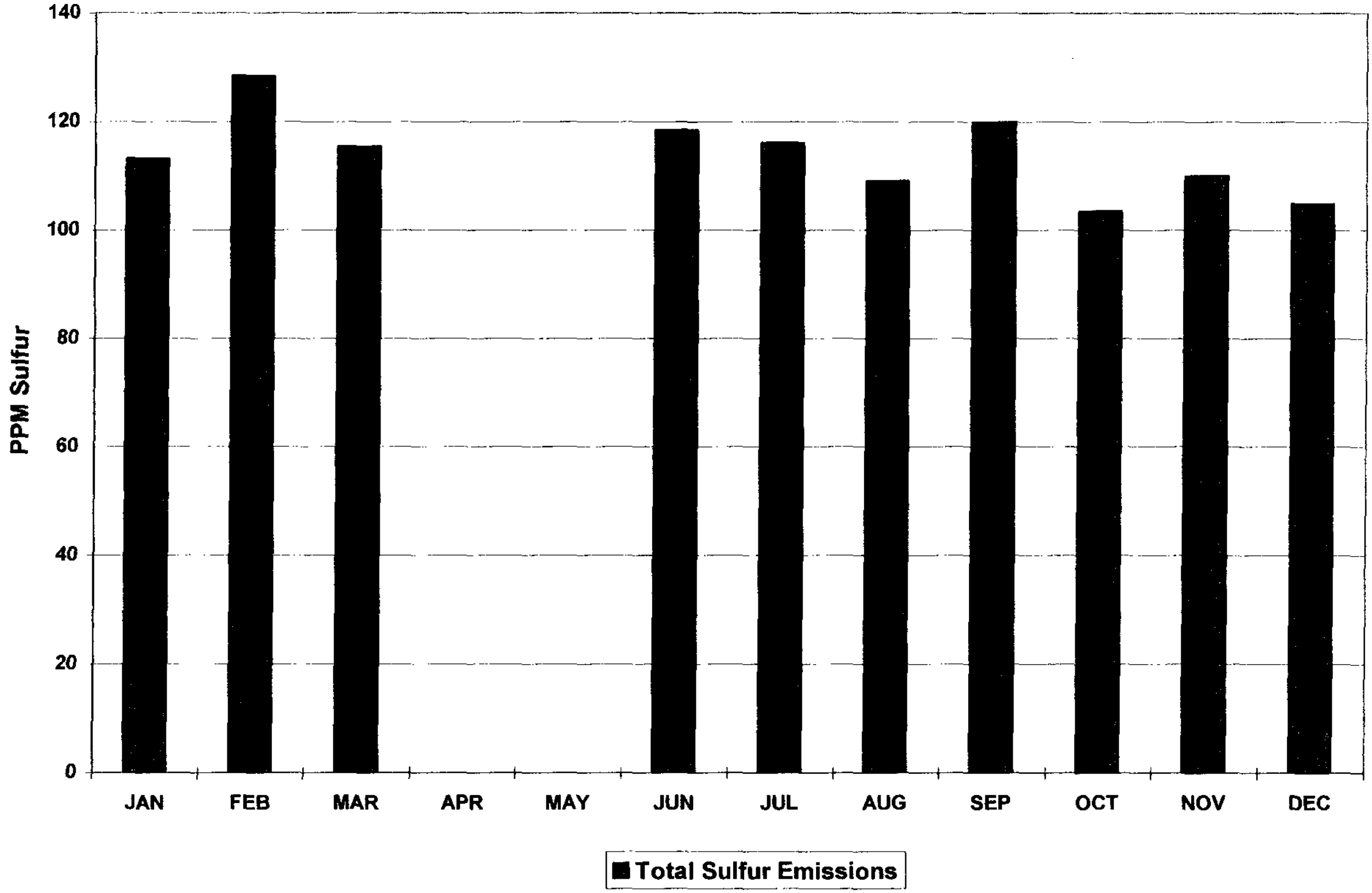
1999 ENERGY UTILIZATION (GASIFIER)
(Mlbs)



1999 COAL FEED TO GASIFIER
(MMBtu's)



1999 TOTAL SULFUR EMISSIONS (PPM as SULFUR)



1999 POUNDS OF SO2/MMBtu OF COAL FEED (TOTAL REPOWERING EMISSIONS)